Coalbed Gas (CBG) opportunities in Crowsnest coalfield

- Information package for potential investors -

November 12, 2003

The Government of BC
Ministry of Energy and Mines
Oil and Gas Division
Oil and Gas Emerging Opportunities & Geosciences Branch

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August 2003

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1 Introduction

The BC government has taken initiatives to make CBG resource more attractive to potential developers and investors. The Ministry of Energy and Mines (MEM) is leading the CBG Strategy, in collaboration with the Oil and Gas Commission, (OGC) to facilitate and stimulate CBG projects across the province. The goal of the MEM is to work together with industry, the federal government and other stakeholders to promote responsible oil and gas development activities in BC.

MEM's CBG strategies:

- Provide information and assistance to proponents interested in exploring and/or developing CBG projects in BC coal basins
- CBG is a key component of Oil and Gas Division's strategy
- CBG legislation enacted to clarify ownership issues and more effectively manage operational issues
- Royalty regime revised to more effectively deal with CBG
- CBG reports, maps and other information made available to industry and public

This information package is intended to provide a general background of CBG development opportunities in Crowsnest coalfield so as to assist in decision-making by potential investors and developers. An outline of the coal resource and geology, historical Exploration and Production (E&P) activities, regulatory process and other useful information for potential investors are provided in the following chapters.

2 Executive Summary

The Crowsnest coalfield is part of the East Kootenay coalfields in southeast BC. Located between the Elk River and the Alberta-BC border, it extends from southeast of Fernie to north of Sparwood. The coal seams occur within the Jura-Cretaceous Mist Mountain Formation. World-class coal resources (nearly 27.7 billion tonnes) are contained in this coalfield and CBG in-place resource in the area is estimated up to 12 Tcf.

Coal and surface ownership in the Crowsnest coalfield is a combination of provincial, freehold and federal land. Currently, the province owns the petroleum and natural gas (P&NG) rights in the coalfield almost exclusively, including in the Dominion Coal Blocks (DCBs).

CBG in-place resource in the Crowsnest coalfield is estimated at 12 Tcf, with over 6 Tcf being within the DCBs. However, the geological complexity of the Crowsnest coalfield must be considered when projecting how much of the CBG may be recoverable. B. Ryan considered this geological complexity and estimated total resource in the area where the Provincial Crown has both coal and P&NG titles to be approximately 2.78 Tcf.

Coal has been mined in the east Kootenays for over 100 years. Until the 1960's, most coal mines were underground coal mines, located close to the rail line along the western side of the coalfield. Coal at all these mines contained methane.

The oil and gas industry has long been interested in this area and during the 1990's, three companies drilled CBG exploration holes in the field and demonstrated mixed results. However, for a number of reasons, the data obtained during these tests have not been considered as representative of CBG potential in the Crowsnest coalfield. CBG exploration projects were also conducted in Elk Valley, Greenhills and several Alberta Foothills locations.

Potential CBG markets include BC, Alberta and the US along with local markets for residential and industrial users. There are TransCanada main pipeline with Terasen's local distribution systems along with extensive electricity transmission systems, a major highway and a number of logging roads available in the area.

The MEM is leading the CBG strategy, in collaboration with the OGC, to facilitate and stimulate CBG projects across the province. The BC government provides policies supportive of oil and gas development, a competitive fiscal regime and one-stop regulatory approval. BC itself offers ready access to Canadian and US markets as well as a skilled service sector.

3 Resource & Geology

3.1 Location and Size of Basin

The Crowsnest coalfield is part of the East Kootenay coalfields in southeast BC. Located between the Elk River and the Alberta-BC border, it extends from southeast of Fernie to north of Sparwood (Map 1). The field is 10-20 km wide, nearly 60 km long and occupies an area of about 60,000 ha (600 km^2). The area is within the Rocky Mountains and includes portions of the MacDonald and Taylor Ranges. Elevations vary from approximately 1000 m in the Elk River valley to 2300 m in the MacDonald Ranges (Map 2).

3.2 Coal Resource

The coal seams occur within the Jura-Cretaceous Mist Mountain Formation in a geological basin bounded by the Borgeau thrust fault on the west and in part by the Flathead fault on the east. Total coal thicknesses in the Mist Mountain Formation vary from an average of about 30 m on the east to 60 m on the west. The coal rank varies from low-to-high volatile bituminous, increasing to the southwest and down dip into the center of the coalfield.

The Crowsnest coalfield has a total estimated coal resource of nearly 27.7 billion tonnes (Johnson and Smith; 1991); approximately 22.6 billion tonnes is within 1000 m of surface (Dolmage and Campbell; 1975). Estimates of the total coal resource of the basin have been made by projecting the volume of Mist Mountain Formation and the cumulative amount of coal in the section. These estimates include coal at unmineable depths.

It is estimated that less than 4 billion tonnes of the total coal resource (28 billion tonnes) may be mineable, of which only 100 million tonnes may be surface mineable. Much of the surface mineable potential occurs in DCB Parcel 73 (76 million tonnes). DCB Parcel 82 has an underground mineable potential of 230 million tonnes. More information on the coal resource estimations and potential mineable resources can be found in the references attached with this document.

3.3 CBG Resource Potential

The combination of area and cumulative coal indicates a large resource of CBG, which has been estimated at 12 Tcf (Johnson and Smith; 1991). CBG resource potential in the DCB is estimated to be 6.57 Tcf to the depth of 1000 m (Dawson et al., 1998; 0.65 Tcf for block 73 and 5.92 Tcf for block 82). Dawson et al., 1998 used estimated gas contents of 16-18 cc/g for all seams although they considered gas contents to vary from 10.9 to 20.1 cc/gm (350-650 scf/t).

However, the geological complexity of the Crowsnest coalfield must be considered when projecting how much of the CBG may be recoverable. The coalfield forms part of the Lewis thrust sheet and therefore had a protracted deformational history. Initial thrusting was followed by folding in the late Jura-Cretaceous and extension on north trending major faults in the Tertiary. The thrusting caused shearing within some seams that is unrelated to the amount subsequent folding. This has possibly impacted permeability and generates fine coal that may make CBG production more difficult.

Successful production will rely on understanding the interplay between deformation coal quality and the location of specific geologic structure. With these caveats in mind the more prospective area may be where the Mist Mountain Formation is in the depth window of approximately 200 to 1000 m. The total resource in the area where the Crown has both coal and P&NG titles (Map 5 & 6) is estimated in very general terms to be 2.78 Tcf (B. Ryan; 2003).

Companies interested in fine-tuning estimates of the resource potential in the coalfield should use the process outlined in the latest B. Ryan paper (Appendix 1) and other references attached as a guide and complete their own assessment. In terms of the recoverable resource, this will depend on the presence of permeability and on the number of seams in the section that can be economically drained of gas. Appendix 1 also contains a number of ideas relating structure coal quality and CBG that may help explorationists locate favorable areas. In addition, more information on BC coal geology and CBG resource can be found by contacting the MEM, Oil and Gas Division, Oil & Gas Emerging Opportunities & Geosciences Branch (Barry Ryan – Coal and Coalbed Methane Specialist; 250-952-0418).

3.4 Previous E&P Activities in Area

3.4.1 Coal Mining

Coal has been mined in the east Kootenays for over 100 years. Until the 1960's, most coal mines were underground coal mines, located close to the rail line along the western side of the Crowsnest coalfield. These included: the Coal Creek Colliery, which opened in 1897, 6 km east of Fernie; Michel Colliery, 28 km north of Fernie; the Morrissey Colliery, 16 km southeast of Fernie and a CPR mine at Hosmer, 11 km north of Fernie. Coal at all these mines contained methane. The coal at Morrissey generally contained more gas than other mines in the area because it was lower in the section and below the regional water table. Since 1970, mining has centered on large open pit mines in both the Elk View and Coal Mountain coal mines.

3.4.2 Conventional Petroleum

The area also has a long history of petroleum exploration. Drilling began in the early 1900's and resulted in some minor oil production. Later, 600 billion cubic feet (Bcf) of CO_2-rich gas were discovered in Paleozoic reservoirs in the Flathead

area, similar to those hosting large gas reserves in adjacent parts of Alberta. The area, which comprises over 6000 km^2, has significant potential yet only 20 wells have been drilled since 1950.

3.4.3 Coalbed Gas

Three companies drilled CBG exploration holes in the field in the 1990's (Mobil/Chevron drilled 2, Gulf Canada drilled 2, Saskoil drilled 4) and demonstrated mixed results. However, for a number of reasons, the data obtained during these tests have not been considered as representative of CBG potential in the Crowsnest coalfield.

Based on these test hole results, a best curve fit to all desorption data from the coalfield indicates a total resource of 6.7 Tcf. Gas contents for the wells ranged from less than 1 cc/g up to 16.56 cc/g. The low gas contents in some of the wells may be due to their being spudded high above the valley floor and perhaps being in coals above the water table. Permeability tests results were performed for some, but results were ambiguous or indicated low to moderate permeability. In most wells the gas content (dry ash free basis) decreased for the lowest seams. This can be explained by changes in petrography with the lower seams being richer in inert macerals, which adsorb less gas. It can also be explained by assuming that all the seams were initially under saturated and those closer to surface were later recharged with biogenic methane. There are indications that biogenic methane is present in the Elk Valley coalfield as well.

CBG exploration projects conducted at nearby areas include:

- Test wells drilled by Fording, Norcen and Suncor in the Elk Valley in the 1990s
- CBG exploration projects were undertaken in the foothills area of Alberta.

The result of these CBG projects can be found at the following reference:

- F.M. Dawson, D.L. Marchioni, T.C. Anderson and W.J. McDougall (2000): An assessment of Coalbed methane exploration projects in Canada, *Geological Survey of Canada Bulletin 549.*

There was also an extensive CBG exploratory project done at Greenhills in September 2000. The information of these test holes will be available to the public 3 years after the project date.

There is little public information available on CBG exploration costs in the Crowsnest coalfield. Proponents should be aware that the complexity of coal geology would dramatically affect the exploration costs. Therefore the selection of drilling locations is critical to economic viability of CBG projects.

4 Potential Market & Logistics

4.1 Potential Market

CBG produced in Crowsnest coalfield could be transported via TransCanada's BC pipeline system or Terasen's local pipeline system distribution to BC, Alberta and the US markets (Map 3). TransCanada's BC pipeline system extends 200 km from Alberta's western border through BC to the US border, serving markets in BC, the Pacific Northwest, California and Nevada.

There are also local market opportunities including both industrial and residential end users. Terasen's local distribution pipeline system comes off Trans Canada's main line, serving the towns of Sparwood, Elkford and some of the mines. Potential industrial end users include major coal mining and forest operating in the area.

- Fording Canadian Coal Trust (www.fording.ca)
  - Fording Inc. – Elk View coal mine operator
  - TeckCominco (www.teckcominco.com) – Coal Mountain coal mine operator
- Tembec (www.tembec.ca) – Forestry operator

Fernie and Sparwood are the closest residential areas with a population of 3,812 and 4,611 respectively (Statistics Canada Y2001). The population for the East Kootenay Regional District covering 27,560.48 square km is 56,291.

4.2 Pipeline and Electricity Transmission Systems

The information on TransCanada's BC pipeline system and Terasen's local distribution system are summarized below. Further inquiries on these pipelines can be directed to TransCanada Pipeline or Terasen Gas.

	BC Systems (TransCanada)	**Foding Coal Lateral (Terasen Gas)**	**Fernie Lateral (Terasen Gas)**
Total Volume Delivered	855 Bcf (2001)	NA (Contact Terasen Gas for details)	NA (Contact Terasen Gas for details)
Diameter	36"	8" – First 34 km 6" – Next 45 km	3"
Pressure Rating (MOP)	6280 kPa	6280 kPa	6280 kPa
Lengths	200 km (170 km of Right of Way)	79 km	24 km
Destination Markets	British Columbia, Pacific Northwest, California, Nevada	Sparwood and Elkford (Fording coal mine)	Farnie

- Terasen Gas (www.terasen.com)
- TransCanada Pipeline (www.transcanada.com)

There are also extensive electricity transmission systems available in the area. Regional load is served from 60 kV to 230 kV transmission systems centered at Cranbrook substations. Transmission lines run from Cranbrook to Fernie, Fernie to Sparwood and Sparwood to Alberta. East Kootenay area is a part of the South Interior bulk transmission system which enables energy interchanges and emergency support with Alberta across one 500 kV line run between BC Hydro's Cranbrook Substation and Alberta's Langdon Substation, near Calgary. Further information on these transmission systems could be directed to BC Transmission Corporation, a subsidiary of BC Hydro.

- British Columbia Transmission Corporation (www.bctransco.com)

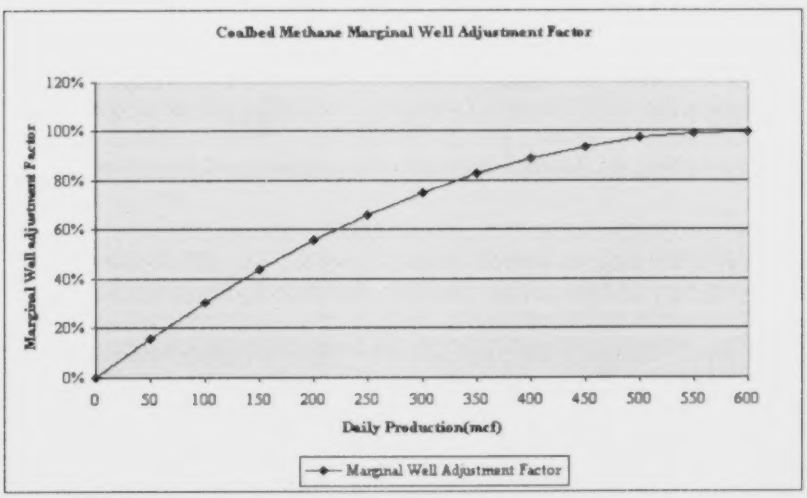
4.3 Surface Access

A major highway (Crowsnest Pass highway Number 3) follows the western margin of the coalfield and a number of logging roads traverse the coalfield. An extensive railway system is available to connect active coal mines and nearby cities.

5 Regulatory Process and Policies

5.1 Royalties

- A new Royalty regime (Amendments to the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation), introduced in March 2002, reflects the unique development and production characteristics of CBG resource and allows a reasonable return to natural gas producers (Appendix 3).
    - Produced-water handling costs are included in the producer cost of service allowance to address the added water management costs
    - A royalty bank was created to collect excess allowance to be used against future assessed CBG royalties
    - Increasing the marginal well adjustment factor threshold to 600,000 cubic feet per day from 180,000 cubic feet per day to address the lower production rates.
    - Providing a $50,000 royalty credit for CBG wells drilled before Feb 29, 2004. This royalty credit will be most likely extended for wells drilled after March 2004.



- The new Summer Royalty Program, introduced in June 2003, allows producers to deduct a summer drilling deduction amount from its total royalty payable to the province if they have one or more interests in a well (Appendix 4).

5.2 Mineral Rights Clarification

- The new *Coalbed Gas Act*, enacted in April 2003, clarifies CBG ownership. CBG is natural gas and is owned by the owner of the natural gas estate in BC (Appendix 2 & 5).

- The "Mineral Ownership Determination Project" is currently undertaken by the Ministry's taskforce to identify and confirm the ownership of minerals originally included in Crown grants. The project will initially focus on the Crowsnest coalfield and Vancouver Island. In conjunction with this project, MEM intends to introduce legislation in 2004 to confirm the identified mineral ownership.

5.3 Efficient and Responsible Regulatory System

- OGC, a Crown corporation created in October 1998, provides an efficient, single-window approach to the regulatory process by effectively streamlining approvals while maintaining provincial environmental standards (Appendix 7).

- *Guidelines for Coalbed Methane Projects in BC*, prepared by OGC in October 2002, clarifies for project proponents and operators the existing regulatory requirements for CBG developments in the province. It is a draft and is subject to revision to reflect the lessons learned as the industry develops in the province (Appendix 9).

- *CBM Produced Water Guideline*, currently being prepared by OGC and Ministry of Water, Land, and Air Protection (WLAP), clarifies the requirements for disposal of water produced from CBG wells. For further information on *CBM Produced Water Guideline*, please contact MEM, Oil ad Gas Division (Vic Levson – Quatemary Geologist, 250-952-0391).

There are guidelines for public involvement and surface rights available through OGC (Appendix 10 & 11). Further general inquires and questions on BC CBG development opportunities, regulatory process and policies could be addressed to the MEM, Oil and Gas Division, Oil & Gas Emerging Opportunities & Geosciences Branch (Mary Coward – CBG Project Manager; 250-356-9827).

6 Tenure & Mineral titles ownership

6.1 Mineral Ownership Determination Project

MEM has a project underway to clarify the mineral rights title status for most of the Crowsnest coalfield and is expected to complete the project by December 2003. General information on rights ownership is provided below.

6.2 Coal and Gas Ownerships in the Crowsnest Coalfield

Coal and surface ownership in the Crowsnest coalfield is a combination of provincial, freehold (25,275 ha by TeckCominco; 11,230 ha by Tembec) and federal land (Map 4 & 5). Most of the freehold lands are located in the northern part of the coalfield. Tembec is the surface owner under which the Province is the coal owner in a further 22,200 ha. DCBs is federal land, which contains two parcels (parcel 73 and 82) an area of about 20,000 ha (200 km^2) in total.

- Freehold
  - TeckCominco - approximately 25,275 hectares
  - Tembec – approximately 11,230 hectares
- Federal land (DCB)
  - Parcel 73 – 2,023 hectares
  - Parcel 82 -18,211 hectares
- Crown land
  - The rest of the coalfield

Except for approximately 2,600 – 4,100 ha which is owned by Shell Canada, the province owns the petroleum and natural gas (P&NG) rights in the coalfield, including in the DCB (Map 6). However, the Provincial Crown P&NG tenure may be acquired by the freehold coal owners (Appendix 6).

To clarify ownership of interested project locations, proponents are encouraged to contact the MEM, Titles Division at the earliest stage of decision-making (Colin Magee – Director, Oil and Gas Titles; 250-952-0335). Titles Division will assist you with pre-tenure planning and petroleum titles information.

6.3 Opportunities For Permitting Multiple Sites Under General Development Permit

Proponents have opportunities to apply for multiple sites under a General Development Permit (GDP) for land tenure in Crowsnest coalfield (Appendix 12). A GDP is an application tool that allows for project level review, consultation and approval in principle for works in a given project area. This process will allow for enhanced First Nations consultation, improved cumulative impact management and reduced processing times for permits and authorizations. A GDP is best suited to development fields on Crown land where multiple wells and pipelines are anticipated during a given drilling season and a high likelihood of drilling

success exists. More information can be found by contacting the Oil and Gas Commission, Applications are located in Ft. St. John (Larry London – Director of Applications and Approvals, Oil and Gas Commission, 250-261-5701)

7 Land Use Issues

7.1 Land Use Plan

The Crowsnest coalfield is contained within the regional Kootenay-Boundary Land-use Plan Implementation Strategy (1997) area. It is also partially within the area covered by the Southern Rocky Mountain Management Plan, a "landscape-level plan" which was recently finalized by the Ministry of Sustainable Resource Management (SRM). These plans apply exclusively to Provincial Crown Lands, and have no influence on private land or the DCB. There are no Special Resource Management (SRM) or Protected Areas in Crowsnest coalfield except parks shown in Map 7. A portion of the northern part of coalfield is designated as Coal Enhanced Resource Development Zones (ERDZ) which signifies a long-term, priority commitment of those areas to coal mining exploration and development. Proponents are encouraged to become familiar with these plans that provide information and guidance on addressing socially and environmentally sensitive values in the area. In addition, proponents should be aware that most of land use conflicts could be mitigated with best management practices.

- Ministry of Sustainable Resource Management – Kootenay-Boundary Regional Land Use Plan
  http://srmwww.gov.bc.ca/rmd/regional/kootenay/index.htm

Potential land use conflicts:

- Forestry
- Recreation
- Hunting
- Coal extraction

Possible wildlife and other issues:

- Dissection of migratory routes
- Habitat loss
- Increased access for hunting
- Introduction of weeds
- Provision of unnatural vantage points for raptors or hazards to flight (e.g. electrical power lines)
- Disturbance during breeding seasons (e.g. due to noise from drilling or compressor stations)
- Possible impacts on endangered species
- Possible damage to or modification of wetlands and riparian zones
- Possible benefits (e.g. using produced CBG waters to enhance or create waterfowl habitat)

Other possible issues:

- First Nations
- Archaeological sites and cultural resources
- Air quality (e.g. diesel generators)
- Vegetation disturbance
- Soil erosion
- Visual impacts (e.g. powerlines and roads disrupt natural views)
- Noise and lights (from compressors, frac equipment etc.)

7.2 First Nations

The Crowsnest coalfield lies within the asserted traditional territory of the Ktunaxa Nation. The Ktunaxa Nation is in Stage 4 of the BC Treaty Commission negotiation process.

The Province has an obligation to consider aboriginal interests in decision-making processes that could lead to impacts on those interests. This obligation is fulfilled in most instances through consultation.

The MEM and the Treaty Negotiation Office are currently engaging with the Ktunaxa Nation on a series of initiatives that have led to increased understanding for all parties and have allowed the Ktunaxa Nation to gain a greater understanding of oil and gas development (Appendix 8). The Ktunaxa Nation see environmentally sound oil and gas development as an economic opportunity and have expressed a desire to be involved in the industry from the beginning and through all stages of development. The Province is encouraging all companies wishing to develop CBG resources in the Kootenay to, at the earliest stages, develop a relationship with the Ktunaxa Nation (and other, non-aboriginal communities).

For more information on consultation requirements, please contact the MEM, External Relations, Aboriginal and Community Relations Branch (Trent Jonson – Senior Advisor; 250-952-0820) and also refer to the Provincial Consultation Guidelines available at TNO website.[1]

For more information regarding the Ktunaxa Nation, or to set up a meeting, please contact KKTC at Cranbrook (Marion Eunson – Employment Development Officer; 250-489-5762).

7.3 Produced Water Management

The Oil and Gas Commission (OGC) regulates all water produced during oil and gas production. At present, most of the produced water is re-injected into

[1] http://www.gov.bc.ca/tno/down/consultation_policy_fn.pdf

subsurface formations, but some CBG development projects may result in quantities of water suitable for surface discharge. An intraministry task force (MEM, OGC, WLAP) is currently developing guidelines for dealing with CBG produced water issues, focusing on practices for water that may be discharged to the surface. If the water quality meets criteria set by WLAP, then the water may be discharged at the surface. Various treatment processes may be available for waters not meeting the WLAP criteria. Water quality data for the Crowsnest coalfield will be collected before a decision on discharge options is made.

7.4 Groundwater

CBG production requires groundwater removal, which may result in lowering of the local water table. In addition, potential issues may arise if the water is discharged into aquifers. Studies on groundwater flow in the Mist Mountain Formation indicated that groundwater contributes <10% of the total direct flow to the Elk River. Therefore, coal bed depressuring should have little impact on the river (Harrison *et al.*, 2000). However, the deformation of strata in mountainous terrain and the influences of large elevation differences on water table locations and gradients make coal bed aquifer documentation complicated.

Consequently, the groundwater system should be studied further. There are a number of water wells in the Fernie area along the Elk River valley but none of them are in the BC provincial database.

7.5 Water Quality Monitoring

The cumulative impact of future CBG developments is difficult to predict. Although no single CBG project may cause unacceptable impacts, collectively CBG development and production over 2 or 3 decades will add to overall cumulative effects in the Crowsnest region. In addition, CBG development may occur in some areas where water quality may be already impacted from recent or current land-use practices. This suggests the importance of surface water quality monitoring both before and during development.

7.6 Best Management Practices

In other jurisdictions where CBG fields are currently being explored, successful strategies for handling produced water are developed. Proponents are encouraged to utilize these strategies to minimize environmental and social impacts.

- Beneficial uses of CBG waters (e.g. for irrigation, drinking water or wetland enhancement)
- Design of various methods for water treatment, water storage and discharge
- Measures for erosion control
- Monitoring plans

- Evaluation of potential effects on other groundwater users

7.7 Environmental Assessment Requirements

Currently, there are no environmental assessment requirements prior to project application. When a proponent submits an application, it is checked for potential impacts on land, fish and wildlife habitat, forest resources, stakeholders, archeology and First Nations. Depending on the project, a CBG application may require assessments for timber harvesting and field, fisheries and habitat and archeological resources as well as First Nations and public consultation. CBG proponents can contact OGC as a single-window approval process where reviews are conducted by interdisciplinary OGC staff, with referrals as needed to other agencies.

Ministry Contacts

Ministry of Energy and Mines (MEM)
Oil and Gas Commission (OGC)

General Inquiries on CBG Development Opportunities Mary Coward (MEM) - Victoria Telephone: (250) 356-9827 Fax: (250) 952-0922 Email: Mary.Coward@gems6.gov.bc.ca	**Policy & Regulations** Ross Curtis (MEM) - Victoria Telephone: (250) 952-0227 Fax: (250) 952-0269 Email: Ross.Curtis@gems9.gov.bc.ca
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Database Information

For selected references to coalfields in BC, coal databases and information concerning coal and CBG visit the BC Geological Survey Branch coal website at: www.em.gov.bc.ca/mining/geolsurv/economicgeology/coal

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References

Available on MEM Oil and Gas Website:
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The Geology and Oil and Gas Potential of the Fernie – Elk Valley Area, Southeastern British Columbia
Dr. Patrick Monahan, P.Geo
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Barry D. Ryan, PhD, P.Geo
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Cleat Development in Some British Columbia Coals
Barry D. Ryan, PhD, P.Geo
2002

Pseudovitrine: possible implications for gas saturation in coals and surrounding rocks
Barry D. Ryan, PhD, P.Geo
2002

Various BC and regional maps, studies on CBG development opportunities throughout BC and Frequently Asked Questions are also available.

Available on OGC Website:
http://www.ogc.gov.bc.ca

Regulations and Handbook

- Drilling and Production Regulation
- Oil and Gas Commission Levy Regulation
- Pipeline Regulation
- Sour Pipeline Regulation
- Oil and Gas Waster Regulation
- Spill Reporting Regulation

- Workers' Compensation Regulations
- Oil and Gas Handbook

Available on Other Ministry Website:

Southern Rocky Mountain Management Plans
Ministry of Sustainable Resource Management, August 2003
http://srmwww.gov.bc.ca/kor/srmmp/srmmp.htm

Kootenay-Boundary Land-use Plan Implementation Strategy
Ministry of Sustainable Resource Management, June 1997
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Other References:

Selected References for East Kootenay Coalfields are available at:
http://www.em.gov.bc.ca/Mining/Geolsurv/coal/coalref.htm

THE CBM RESOURCE OF SOME PROSPECTIVE AREAS OF THE CROWSNEST COALFIELD

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Ministry of Energy and Mines

Introduction

The Crowsnest Coalfield is located between the Elk River and Michel Creek drainages and covers a total area of about 600 square kilometres. A major pipeline, which, trends north south through the coalfield (Figure 1), connects the Alberta gas fields with the US market. This pipeline has been expanded from the original 36-inches Trans Canada pipeline and is now twinned with a 48-inch Foothills pipeline following the same right-of-way. An 8-inch pipeline, which branches off the main line in the northeast corner of the coalfield, serves the towns of Sparwood, Elkford and some of the mines. A second 8-inch pipe line branches off at Morrissey and serves the town of Fernie. Title to the gas rights in the coalfield is in part with the crown and in part un assigned at this time. This paper summarizes existing mapping data, coal quality and coal resource data. It also attempts to delineate the resource potential of areas where the crown has clear title. This means disregarding areas where various companies have at least freehold coal rights.

The Crowsnest Coalfield has been mapped by a number of geologists. One of the earliest was Newmarch (1953) who provided a preliminary map of the coalfield and detailed geology of the Coal Creek area, which was compiled at a time when the mines in the creek were still operating. Price (1961) produced a regional map of the Crowsnest Coalfield, which also provides strike/dip information. The area was mapped in the period 1977 to 1981 using orthophotos by a number of personnel from the British Columbia Ministry of Mines (Pearson *et al.*, 1977; Pearson and Grieve, 1978; Pearson and Grieve, 1980). These maps outline seam trends and provide structural information. A recently a compilation of the mapping and construction of geological sections was completed by Johnson and Smith (1991). Other recent studies such as Dawson *et al.* (1998) have used these maps and accompanying sections. Monahan (2002), as part of an assessment of the oil and gas potential of the area, produced a revised map using existing mapping and well data.

The map from Johnson and Smith is reproduced here (Figure 1) with addition information, which includes, approximate delineation of various land blocks, areas in which the Mist Mountain Formation is at least in part at a depth of less than 1000 metre and fold axial plunge data transferred from Price (1961). In addition geological sections from Johnson and Smith (1991) are reproduced with some additional sections to give a spacing of 5 kilometres for sections through the coalfield (Figure 2). The 1000 metre depth line is shown on the sections.

There are a number of publications that deal with coal quality and surface and underground coal resources of the coalfield. A summary paper (Pearson and Grieve, 1985) discusses coal quality. Coal rank in the coalfield varies from high-volatile bituminous to low-volatile bituminous, with higher rank coals in the southwest part of the basin. There is also evidence that rank increases down dip into the core of the major syncline that crosses Morrissey Creek

Johnson and Smith (1991) were the first to estimate the CBM resource of the coalfield and they calculated a value of 12 Tcf. They used an average gas *versus* depth curve derived from data from the San Juan basin. In 1990 a number of companies drilled stratigraphic test holes in the southern part of the coalfield (Dawson *et al.*, 2000) (Figure 3). A best curve fit to all desorption data (Figure 4) resulting from this drilling in the coalfield indicates a lower total resource for the coalfield of 6.7 Tcf.

To date the only assessment that covers parts of the coalfield is that by Dawson *et al.* (1998) who assessed the CBM resource potential of the two Dominion Blocks (block 73 in the north and block 82 in the south) (Figure 1). These blocks have a total area of 202 square kilometres (block 73 = 20.2 and block 82 = 182.1 square kilometres). Dawson *et al.* (1998) considered gas contents to vary from 10.9 to 20.1 cc/gm (350 – 650 scf/t). They estimated a total resource for the two blocks of 6.57 Tcf to a depth of 1000 metres. The northern block 73 having 0.65 Tcf (93% shallower than 1000 metres) and block 82 having 5.92 Tcf (62% shallower than 1000 metres) providing a resource shallower than 1000 metres of 4.28 Tcf. They used estimated gas contents of 16 and 18 cc/g applied to all

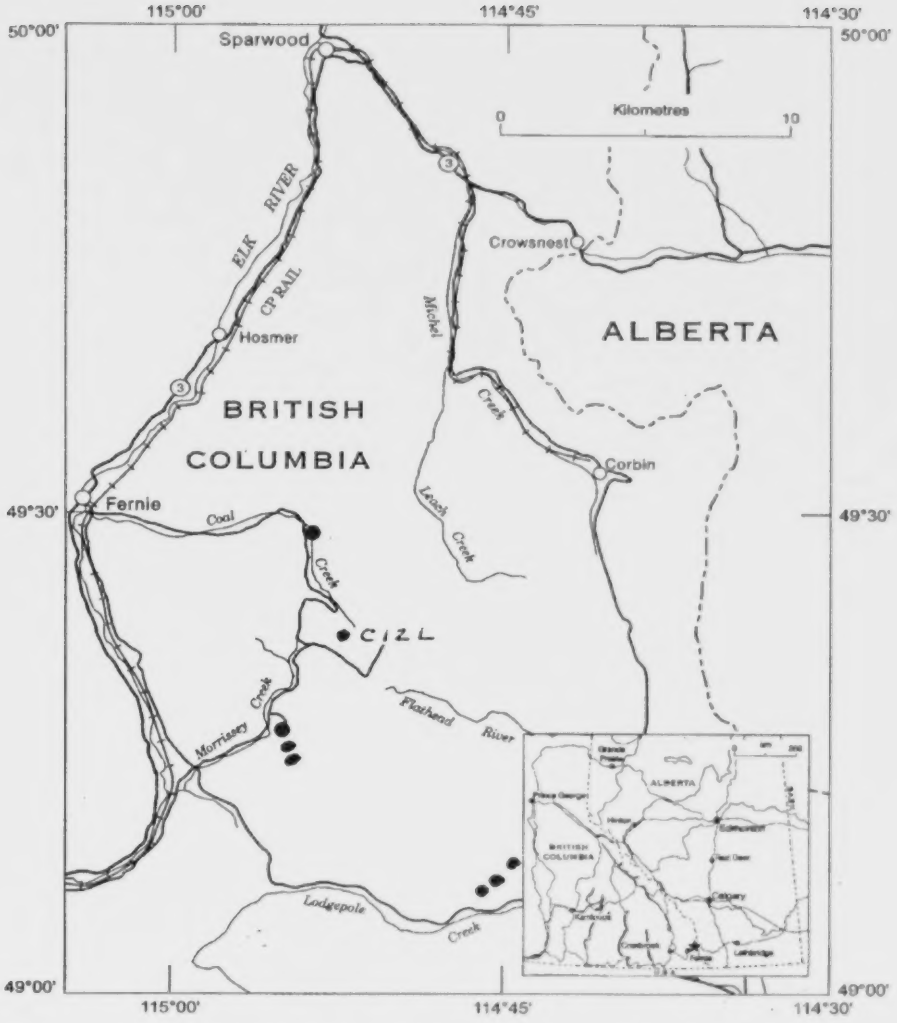


Figure 3: Location of Stratigraphic test holes drilled in 1990, data from Dawson *et al.* (2000).

seams (Table 1). The specific seam thickness and gas content values used by Dawson *et al.* (1998) seem to be high, based on available desorption data (Figure 4) and on cumulative coal thickness data for the Crowsnest Coalfield as a whole (Table 2).

Dawson *et al.* (1998) used the seam designation applied to the northern part of the Crowsnest Coalfield where the basal seam is number 10. Some papers (for example Newmarch, 1953) designate the basal seam in the Crowsnest Coalfield as 1 Seam and count up section. People checking literature on coal in southeast BC should make sure they know the specific seam designation being used in each paper.

In the Crowsnest Coalfield formations above the Mist Mountain include the Elk Formation and Blairmore Group (Figure 5), which includes the basal Cadomin Formation and overlying lower and middle Blairmore rocks. Most authors indicate that the Elk and Mist Mountain formations thin to the east. Table 3 summarizes some of the thickness information available in a number of papers.

Stratigraphy

Any estimation of the depth to the Mist Mountain Formation requires at least some knowledge of the thickness of overlying formations and of the regional dips.

Newmarch (1953) indicates that Kootenay Group, which includes the Elk and Mist Mountain formations, varies in thickness along the western margin of the coalfield from 1097 metres at Michel to 686 metres at Hosmer and 625 metres at Fernie. The Kootenay Group is described as 305 to 777 metres thick (Crabb, 1957). It thins to the east in the Lewis thrust block (Price 1964) and is 1076 metres at Coal Creek; 488 metres at Mt Taylor and

Table 1: Dominion blocks CBM resource summary from Dawson *et al.* (1998)

BLOCK 65

	Mt Taylor		A-A						
seam	250-500			500-1000			1000-1500		
	thick	gas	bcf	thick	gas	bcf	thick	gas	bcf
1	2.86	16.6	0	2.86	18	6.14	2.86	18	3.61
2	2.13	16.6	0	2.13	18	5.66	2.13	18	1.62
3	7.68	16.6	0	7.68	18	21.84	7.68	18	4.1
4	1	16.6	0.27	1	18	3.18			
5	10.61	16.6	6.19	10.61	18	30.63			
6	1.16	16.6	0.7	1.16	18	3			
7	5.39	16.6	3.11	5.39	18	12.13			
8	13.23	16.6	9.56	13.23	18	23.87			
9	5.79	16.6	4.37	5.79	18	7.66			
10	1.31	16.6	1.16	1.31	18	1.2			
B	2.47	16.6	2.32	2.47	18	1.74			
totals	53.63		27.68	53.63		117.05			9.33

	Mt Taylor		B-B						
seam	500-1000			1000-1500			>1500		
	thick	gas	bcf	thick	gas	bcf	thick	gas	bcf
1	2.86	18	23.47	2.86	18	13.75	2.86	18	6.34
2	2.13	18	16.31	2.13	18	9.34	2.13	18	3.29
3	7.68	18	25.83	7.68	18	33.28	7.68	18	7.48
4	1	18	5.25	1	18	4.26			
5	10.61	18	60.11	10.61	18	42.66			
6	1.16	18	8.57	1.16	18	3.51			
7	5.39	18	45.79	5.39	18	8.56			
8	13.23	18	121.93						
9	5.79	18	49.5						
10	1.31	18	10.24						
B	2.47	18	15.85						
totals	53.63		382.85	30.83		115.36	12.67		17.11

	Lookout		C-C						
seam	250-500			500-1000			1000-1500		
	thick	gas	bcf	thick	gas	bcf	thick	gas	bcf
1				33.8	18	116.67	33.8	18	63.37
2				5.2	18	27.67	5.2	18	3.41
3				12.2	18	72.98			
5	9	16	20.07	9	18	39.79			
6	4.8	16	14.17	4.8	18	18			
9	2.5	16	6.82	2.5	18	6.14			
10	1.8	16	4.97	1.8	18	3.63			
totals	18.1		46.03	69.3		284.88	39		66.78

	Lookout		D-D			
seam	1000-1500			>1500		
	thick	gas	bcf	thick	gas	bcf
1				12.11	18	161.36
2				14.4	18	191.87
3	3.55	18	10.72	3.55	18	35.51
4	11.04	18	55.58	11.04	18	91.89
5	13.07	18	156.16	13.07	18	23.69
7	1	18	13.32			
9	1.7	18	22.65			
10	1	18	13.32			
totals	31.36		271.75			504.32
south extension	54.17	18	612.83	54.17	18	573.65
totals		total	884.58	54.17		1077.97

	Pipeline	C-C
seam	500-1000	
	thick	gas	bcf
1	33.8	18	1410.14
2	5.2	18	216.94
3	12.2	18	508.98
5	9	18	375.48
6	4.8	18	200.26
9	2.5	18	104.3
10	1.8	18	75.1
totals	69.3		2891.2

total <1000 metres	3.42	tcf
total	5.77	tcf

396 metres 12.1 km northeast from the mouth of Lodgepole Creek (Price, 1961).

The Mist Mountain Formation at Coal Creek is described as 645 metres thick (Gibsons, 1985) or 629 metres thick (Newmarch, 1953). Gibsons (1985) states that it is up to 625 metres thick in southeast British Columbia. Pearson and Grieve (1978) provide a number of Mist Mountain sections for the western and southern margins of the coalfield (Table 3) that range from 657 to 490 metres in thickness. The overlying Elk Formation varies in thickness up to 488 metres (Gibson, 1977), (Jansa, 1972).

Table 2:
Cumulative coal thicknesses for sections in the Crowsnest Coalfield

seam	Fernie Ridge	Morrissey Ridge	Coal Creek	Hosmer Ridge	West Lodgepole	North Lodgepole	Mclatchie Creek	Martin Ridge	Parcel 73
11	4.48	0.00	2.44						
10	2.44	2.32	2.44						
9	3.23	3.38	3.20						
8	6.22	2.19	1.37	1.52					
7	2.99	5.09	0.30	5.79	5.94			1.52	
6	2.77	2.41	0.76	10.67	2.65			6.00	6.10
5	7.25	3.72	5.49	1.83	8.08	6.40		5.43	1.50
4	3.41	4.15	3.81	2.13	6.89	5.79	7.62	2.20	
3	4.02	9.57	2.44	11.58	9.33	7.92	7.47	8.35	11.30
2	6.71	5.49	7.62	5.79				8.02	18.89
1	4.30	7.22	6.10	6.10	14.02	12.19	6.64		
			3.05						
			3.66						
total	**47.82**	**45.54**	**42.68**	**45.42**	**46.91**	**32.31**	**21.73**	**31.53**	**37.79**

note seam 11=B seam

Table 3:
Summary of stratigraphic thicknesses for Jura-Cretaceous units

location	thickness metres	
		Blairmore Group
Coal Creek	610	Lower Blairmore Price, R.A. (1961)
McEvoy Syncline	365-2000	Blairmore Price, R A. (1961)
west	700	Blairmore Crabb, J. (1957)
east	305	Blairmore Crabb, J. (1957)
		Cadomin Formation
Coal Creek	185	Jansa, L. (1972)
Michel	731	Jansa, L. (1972)
Coal Creek	32	McLean, J. R. (1977)
		Kootenay Group
lodgepole	549	Price, R.A. (1961)
Mt Taylor	465	Price, R.A. (1964)
West	700	Crabb, J. (1957)
East	305	Crabb, J. (1957)
		Elk Formation
SE BC	up to 488	Gibson, D.W. (1977)
Michel	483	Jansa, L. (1972)
Coal Creek	519	Jansa, L. (1972)
		Mist Mountian Fomraion
Lodgepole	490	Pearson, D.E. and Grieve, D.A. (1978)
Flathead	604	Pearson, D.E. and Grieve, D.A. (1978)
Morrissey Creek	663	Pearson, D.E. and Grieve, D.A. (1978)
Morrissey Ridge	460	Pearson, D.E. and Grieve, D.A. (1978)
Coal Creek	616	Pearson, D.E. and Grieve, D.A. (1978)
Coal Creek	645	Gibson, D.W. (1985)
Coal Creek	617	Jansa, L. (1972)
Coal Creek	629	Newmarch, C.B. (1953)
Fernie Ridge	634	Pearson, D.E. and Grieve, D.A. (1978)
Hosmer	657	Pearson, D.E. and Grieve, D.A. (1978)
Sparwood Ridge	628	Pearson, D.E. and Grieve, D.A. (1978)
Michel	645	Jansa, L. (1972)

The Cadomin Formation forms the base of the Blairmore Group and ranges up to 170 metres thick (White and Leckie, 2000). The formation is 137 to168 meters thick on the east side of the McEvoy Syncline and 184 metres thick at Coal Creek. The Blairmore group thins to the east and Crabb (1957) provides thicknesses of 700 metres on the west and 300 metes on the east. Price (1961) quotes thicknesses of 365 to 2000 metres.
The Blairmore Group is overlain by the upper Cretaceous Crowsnest Formation (mainly alkaline volcanics), which is 40-100 metres thick below the Lewis Thrust, but does not occur within the thrust sheet. Outcrops of the Upper Cretaceous Alberta Group only survive in the Crowsnest Coalfield in the core of the McEvoy Syncline where it is up to 229 metres thick.

Stratigraphic thickness data is essential for estimating depth to the prospective seams in the Mist Mountain Formation. However thicknesses need to be adjusted to take account of bed dips. As mentioned strike and dip data is available on a number of published maps and is not reproduced in Figure 1. A simple nomograph (Figure 6), in conjunction with Table 3, provides estimates of drill depth to seams in the Mist Mountain Formation.

Coal Sections

There has been very limited exploration in the center of the coalfield where the Mist Mountain Formation does not outcrop, consequently most of the information on seam thickness and cumulative coal thickness in the Mist Mountain Formation comes from mapping, exploration and mining along the western and southern margin of the coalfield. There are a number of partial coal sections described for the purpose of estimating mineable reserves. It is probable that in many cases these sections do not document all coal in the formation, so that cumulative coal thicknesses probably represent minimum values. Data (Table 2 and Figure 7) indicate that cumulative coal thicknesses range from 40 to 50 metres on the west and

between 30 and 40 metres on the east. Seams generally decrease in thickness up section and the third or second seam from the base is usually the thickest.

Coal rank and maceral data

Coal rank varies from high-volatile bituminous to low-volatile bituminous increasing down dip to the east and along strike to the south (Pearson and Grieve, 1985). . There is also evidence that rank increases down dip into the core of the major syncline that crosses Morrissey Creek. If rank increases down dip into major synclines, then upward migration of biogenic methane may saturate up dip lower rank coal within a seam leaving the deeper higher rank parts of a seam under saturated. Obviously production from a shallow saturated seam, with lower gas content, is more economic than production from a deeper under saturated seam with higher gas content. Rank gradients range from 0.01 to 0.12 (delta Rmax/100 metres) (Figure 8).

Adsorption characteristics of seams are controlled by environmental factors (depth and temperature) and physical properties such as rank and maceral content. Jura-Cretaceous coals in southeast British Columbia differ from many coals now producing CBM in that they have high and variable contents of organic inert macerals on a mineral matter free basis (mmfb). These are grouped under the name inerts and include in part the macerals, fusinite, semi fusinite, inertodetrinite and macrinite. Various sub varieties of the vitrinite maceral make up the rest of the seam on an mmfb. The inert macerals when compared to the vitrinite macerals are characterized by lower adsorption ability, higher diffusivity and greater strength. The inert maceral content of seams (mmfb) varies and tends to increase down section with rank (Figure 7); though it is usually the second or third seam above the base of the section that contains the highest inert maceral content. There is also a tendency for the upper parts of seams to be vitrinite rich. The lower parts of seams with higher inertinite content will have

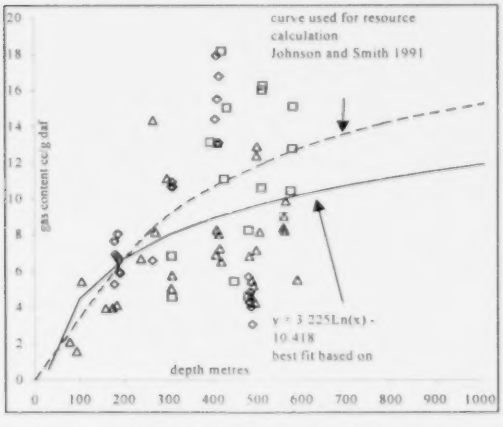


Figure 4: desorption data Crowsnest Coalfield.

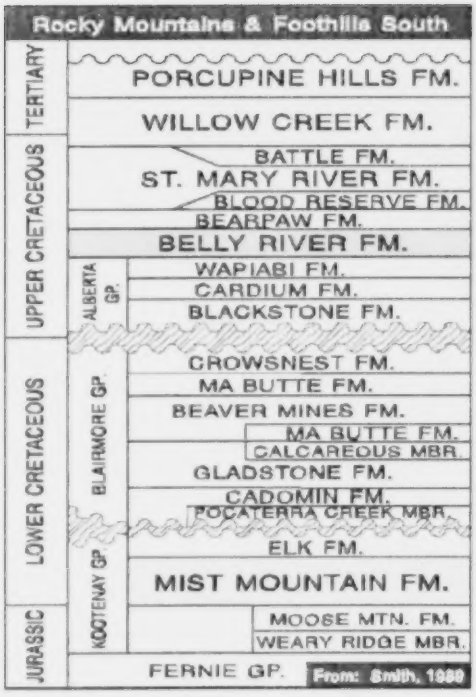


Figure 5: Statigraphic Table from Smith, (1989)

better diffusivity and may be less sheared.

CBM resource area

Experience in moderately deformed coals indicates that, except in unusual structural environments, reasonable permeability (>2mD) does not extend below about 1000 metres. Areas where at least the top of the Mist Mountain Formation is less than 1000 metres from surface are outlined on the map derived from Johnson and Smith (Figure 1) and in the accompanying sections (Figure 2).

The eastern margin of the Crowsnest Coalfield is in part defined by the Erickson/Flathead normal fault system, which by down dropping the Kootenay Group on the west by 1000 to 3000 metres has preserved the coalfield. A simplified structural model of the coalfield is represented by two thrust blocks each containing a north trending syncline. The Sparwood Syncline (Dawson *et al.*, 1998) in the north and the McEvoy Syncline in the south (Price 1961) are the dominant structures in the block below the Lookout/Dominion thrust and above the Erickson/Flathead normal fault. Above the Lookout/Dominion thrust, the tight Hosmer Syncline (Dawson *et al.*, 1998) is cut off by a thrust north of Hosmer. To the south the syncline opens up, has very flat limbs and merges with the flat limb of the McEvoy syncline.

Within these two synclinal trends there are obviously areas where seams are too shallow to contain gas. This depth depends on topography and groundwater

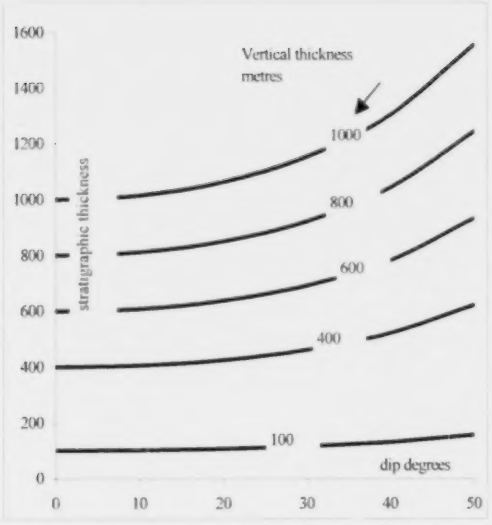


Figure 6: Nomograph of vertical thickness from dip and stratigraphic thickness.

flow patterns. Ideally groundwater flow should be down dip and away from seam outcrop. Generally seams below 200 metres and not intersected close to valley walls or above valley floor should contain gas and consequently areas where Mist Mountain Formation seams are between 200-1000 metres of surface are most perspective for CBM. There is insufficient structural control to accurately delineate the 200-metre depth to the Mist Mountain Formation. As a conservative approximation the formation is assumed to be at a depth greater than 200 metres where ever it was overlain by the full thickness of the Elk Formation, which varies in thickness up to 488 metres (Gibson, 1977). This line is easy to mark on Figure 1 and with data from the sections (Figure 2) helps delineates the area prospective for CBM. Figure 1 also locates the two dominion blocks (73 and 82) and areas where companies have freehold coal rights. Data are derived from standard 1 to 50 000 topographic maps and Grieve and Kilby (1989).

It appears that potential exists in three areas where the crown has gas rights. These areas are:
A/ Headwaters of Bray and Martin Creeks.
B/ Dominion block 73.
C/ West of Dominion Block 82 and the south west part of the block.

Area A

The main area where the BC government has the gas rights covers the head-waters of Bray and Martin Creeks, north of Coal Creek (Figure 1). The area includes parts of Block 82 and skirts the freehold blocks in the center of the coalfield. The area is about 93 square kilometres. The area overlies the west limb of the Coal Creek Syncline, which is traced north from the headwaters of Coal Creek. In the north it plunges to the southwest at 10 to 30 degrees (Armstrong *et al.*, 1976) with dips on the limbs increasing to the north. In the south the syncline plunges to the north (Price 1961). The Dominion Thrust progressively cuts off the east limb of the syncline and it is not present in Dominion Block 73.

The west limb of the syncline is steep an over ridden by a number of thrusts. There are probably more thrusts than are mapped and they will tend to seal seams so that up dip migration of gas to the west will be limited and water movement in seams will probably be along the up plunge direction of the syncline either to the north or south. Steeply dipping seams below thrusts probably initially developed west dipping shear surfaces that as the seam is rotated become near horizontal. A vertical hole drilled into these seams will intersect an extended apparent thickness of coal with near horizontal fractures. Fracing of these seams at shallow depth will open up the fractures in directions extending along strike to the north and south. Drainage areas may extend along strike and not up and down dip. Holes may access structural traps below west dipping thrusts. Also as hydrostatic pressure is decreased the effective lithostatic pressure will be somewhat reduced because the increased amount of low density coal in the vertical column.

Mining occurred from 1908 to 1914 west of an area near Hosmer Creek. Portals were driven through the Fernie Formation into the Mist Mountain Formation, which contains at least 10 seams and the basal Number 1 seam was mined for a time. The Mist Mountain Formation is described as 762 metres thick with 79 metres of coal (Armstrong, *et. al.*, 1976) however these may be apparent not true thicknesses based on thicknesses quoted elsewhere (Table 2, 3), which indicate true cumulative coal thicknesses ranging from 45 metres at Hosmer to 31 metres on Martin Ridge. The rank at Hosmer Creek ranges from 0.95% to 1.19% with a gradient of 0.12 delta Rmax per 100 metres and to the east on Martin Ridge from 0.83% to 0.91% (gradient 0.03 delta Rmax per 100 metres). To the north in Dominion Block 73, rank of the basal seam is 1.16% (Grieve and Kilby, 1989). In the past, there was a lot of exploration and mining to the south in the Coal and Morrissey Creeks and adjacent areas. In these areas the Mist Mountain section contains between 45 and 48 metres of coal dispersed in about 11 seams.

Gulf Canada drilled a 590 metre stratigraphic test hole (hole C12L, Dawson *et al.*, 2000) (Figure 3) south of the area at the head waters of Martin and Coal creeks. The hole intersected 24.4 metres of coal in the top 280 metres of the Mist Mountain Formation. It was drilled west of a major thrust into an area where the Mist Mountain Formation is flat dipping. Gas contents indicate that coals are under saturated, but gas contents were higher than in holes drilled by other companies further to the south. Data for coals near the bottom of the hole indicate that coals are close to saturated. These seams are in the mid part of the Mist Mountain Formation section. The lowermost coal was the thickest and this may correspond to seam 5 in the

Morrissey and Fernie Ridge sections, in which case the coal remaining lower in the section would be between 18 and 24 metres cumulative thickness providing a possible total cumulative thickness ranging of between 42 to 48 metres.

No detailed estimates of the coal resources in Area A delineated in Figure 1 exist. However mining studies estimate a coal resource on Hosmer Ridge of about 700 million tonnes to 760 metres. Alternatively the resource can be estimated by utilizing the area of 93 square kilometers and a cumulative coal thickness of 45 metres and this provides an estimated coal resource of 5200 million tonnes.

The average gas content of the Gulf Canada hole is about 10 cc/g on an as received basis. This is probably a low average value to use for resource estimates however the value of 18 cc/g used by Dawson *et al.* (1998) may be high. Using the lower gas content of 10 cc/g, provides an estimated in place resource of about 1.6 Tcf.

Area B

The Dominion block 73 covers an area of 20.23 square kilometres. Dawson *et al.* (1998) calculated a CBM potential resource of 0.32 Tcf to 1000 metres (Table 1). They provide a 750 metre thick stratigraphic section of Mist Mountain that appears to contain over 70 metres of cumulative coal. Grieve and Kilby (1989) identified a section of 480 metres, which excludes seams number 1 and 2, and contains 37.8 metres of coal up to and including 3 Seam. The basal seam has a rank of 1.16% but ranks appear to increase down dip and definitely increase to the south.

Structurally most of block 73 is in a thrust block below the Dominion/Lookout Thrust and east of area A. The structural style is similar to that of area A, being a syncline with steep dipping west limb and shallow east limb Opportunities for thrust generated traps in the steep dipping west limb exist. The syncline is along the trend of the McEvoy syncline to the south and Sparwood Syncline to the north. The Sparwood Syncline trends across Michel Creek to the north where it becomes the Elk Syncline in the Elkview Coal mine north of Highway 3 at the north end of the Crowsnest Coalfield.

The coal potential was analyzed by Grieve and Kilby (1989) who used seams with a cumulative thickness of 37.8 metres in their study. The thickness of coal available for CBM resource calculations is probably between this thickness and the thickness used by Dawson *et al* (1998). They provide a total coal resource in the block of about 1 billion tonnes, which agrees with the estimate provided by Latour (1970). The tonnage estimated to be shallower than 1000 metres is 550 million tonnes. Dawson *et al.* (1998) used an average gas content of 18 cc/g for all coal deeper than 250 metres and calculated a gas resource of 0.32 Tcf. Using a lower gas content of 10 cc/g (320 scf/t) this resource decreases to 0.18 Tcf.

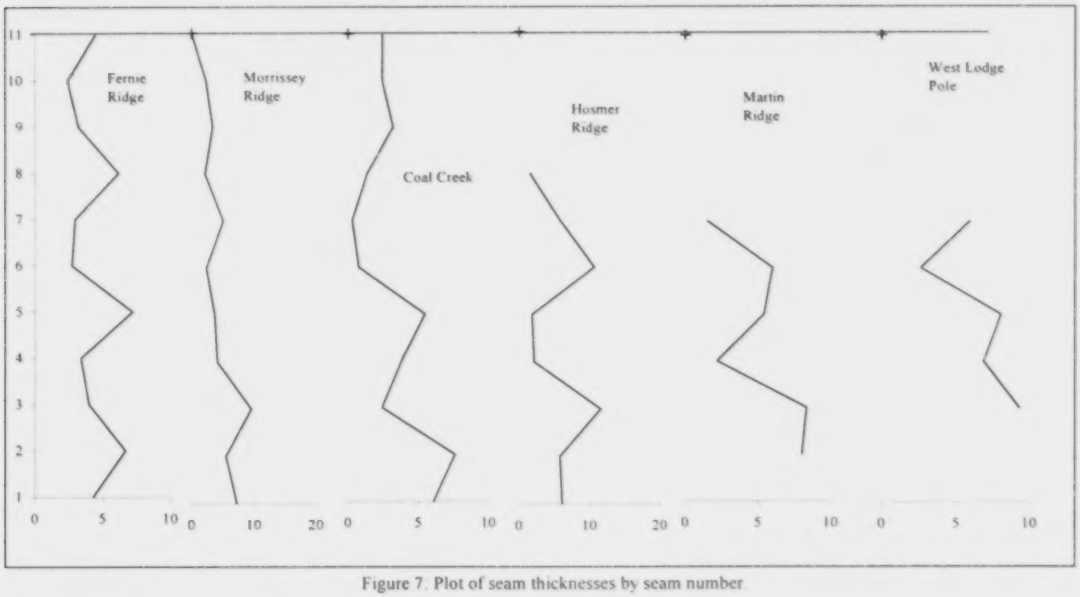


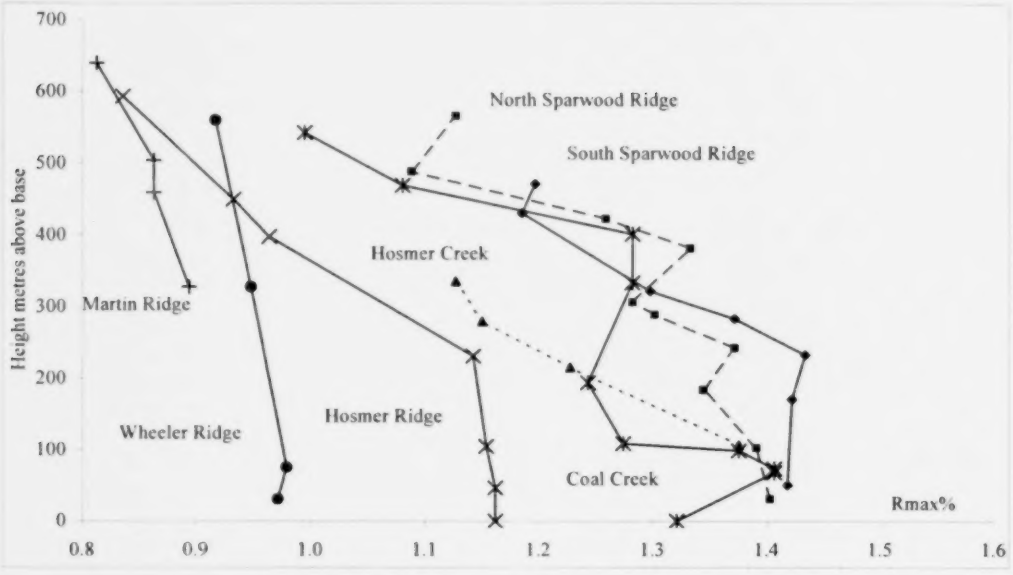
Figure 7. Plot of seam thicknesses by seam number

Area C

In the south, the southern extension of the Hosmer Syncline is ill defined and dips west of Morrissey ridge are flat. There is an extensive area where the Mist Mountain Formation is flat dipping and at least in part shallower than 1000 metres. There are also some areas where the formation on the west limb of the McEvoy Syncline is shallower than 1000 metres. In this area the offset on the Lookout/Dominion Thrust reverses and it is shown on sections in the south as a normal fault (Figures 1 and 2). If this interpretation is correct, then the southern area west of

the fault should have experienced extension at the time of faulting and may still have better permeability on cleats.

Morrissey Ridges ranges from low-volatile bituminous to high-volatile bituminous in rank (Figure 8). The vitrinite



gradient Rmax/100 metres

Wheeler Ridge	0.01	Hosmer Creek	0.12	North Sparwood	0.08
Martin Ridge	0.03	Coal Creek	0.07	South Sparwood	0.08
Hosmer ridge	0.06				

Figure 8: Rank gradients in the Crowsnest Coalfield.

Most of Area C is within Block 82 with some of the area on the southwestern margin of the block. The total area is about 51 square kilometers. Block 82 has a CBM resource potential of 3.42 Tcf to 1000 metres (Dawson *et al,* 1998) and most of this is in the Pipeline area (Table 1) in the southwest where the pipeline crosses the area trending north through the coal field. The centre and northern part of the block is underlain by the McEvoy Syncline, which is cored by the Blairmore Formation and younger rocks. Based on the presence of these formations and their thicknesses the Mist Mountain Formation is over 1000 meters deep in the core of the syncline.
In the southwest of Block 82 there is an area where the east limb of the southern extension of Coal Creek syncline is flat and partially within the 1000 metre depth window. Small changes in the structural interpretation could change the resource assessment significantly.

Saskoil (Dawson *et al,* 2000) drilled two holes in 1991 in the Lodgepole Creek area. The holes were drilled near the subcrop in different parts of the Mist Mountain Formation. By combining the data from the holes, it appears that in the area, the full Mist Mountain Section is 500 metres thick and contains a cumulative coal thickness of 63 metres. To the west the cumulative coal in the section at Coal Creek is 42.7 metres and at Morrissey Ridge 45.5 metres.

The rank of coal to the west under Fernie and reflectance values are 1.45% for the basal seam at Morrissey Creek decreasing to 1.38% at Coal Creek. However rank appears to increase down dip to the east into the syncline (Pearson and Grieve, 1978).

Gas contents of samples from the holes drilled by Saskoil were low but are probably not representative of contents further to the northeast. For the purposes of calculation an assumed gas content of 10 cc/g (320 scf/t) is used. This is considerably lower than the value used by Dawson *et al.* (1998) but is approximately the average gas content for samples from hole C12 L drilled by Gulf (Figure 3).

Based on an area of 51 square kilometers, 50 metres cumulative coal and a gas content of 10 cc/g the CBM resource is 1 Tcf.

Estimated resource available on crown lands

The total resource estimated in the three areas is 2.78 Tcf (Table 4). This is an estimate of the gas resource available in all the coal in the section to a depth of 1000 metres. It is derived using a conservative gas content value but assumes that all the area outlined is underlain by the full coal section and this is probably an optimistic assumption. Other than the order of magnitude size of the 2.78 Tcf resource and the general areas to which it is

Table 4 CBM resources in areas where the Crown has gas rights

	Reference	gas cc/g	billion tonnes	total gas tcf
Area A	south of Dominion Block 73	10	5.2	1.6
Area B	Dominion Block 73	10	0.56	0.18
Area C	part of Dominion Block 82 and area to west	10	3.06	1
		total	**8.82**	**2.78**

assigned, not too much significance should attached to its value. Companies interested in fine-tuning estimates of the resource potential in the coalfield should use the process and references outlined in this paper as a guide and complete their own assessment. In terms of the available reserve this will depend on the presence of permeability and on the number of seams in the section that can be economically drained of gas.

Coal Quality and implications for CBM production

If higher rank coals are to achieve gas saturation or near gas saturation at present depths then it is probable that a large component of the gas will be biogenic. One should therefore consider the conditions that favour generation and retention of biogenic gas, which is generated on coal surfaces and then penetrates the micro porosity to be adsorbed. Excessive water movement will limit the ability of biogenic gas to migrate into coal micro porosity and be adsorbed. Some seams in the Crowsnest Coalfield are sheared, which increases surface area available for bacteria but limits the ability of a seam to maintain permeability when hydrostatic pressure is decreased. In situations where biogenic gas is generated down dip within a syncline limb, introduction of hot CO_2 could initiate up dip movement of water, CO_2 in solution and methane, without any decrease in hydrostatic pressure. Hot CO_2 would be readily available from a coal fired power plant.

Coal petrography varies and seams lower in the section contain more inertinite on a mineral matter free basis. However it is often the 3rd seam above the Moose Mountain Member that contains the most inertinite (Pearson and Grieve, 1978). The inertinite content of seams varies from hanging wall to footwall with the lower parts of seams having consistently higher inertinite contents (Pearson and Grieve, 1985). As a maceral group inertinite is stronger than vitrinite and resists shearing better. It has lower adsorption abilities and higher diffusivities. These properties may be advantageous for CBM recovery. In thick seams that are initially under saturated, but in which biogenic methane is being generated in the micro fractures of the coal, inert macerals will reach re saturation sooner because of lower demands and better diffusivity of methane from micro fractures into the micro pores. A seam may therefore be partitioned with the lower inertinite rich part being saturated at a moderate gas content and the upper vitrinite rich part being under saturated possibly with the same gas content. Completion in the whole seam may result in no gas reaching surface because gas released from one part of the seam may be adsorbed by another part. Completion in the inertinite rich lower part of the seam may result in immediate gas production. The higher diffusivity and strength of the inertinite should help it maintain fracture opening and permeability despite the fact that there is probably less matrix shrinkage to aid permeability.

In the Elk Formation, there are some thin coal seams, which are generally less than 1 metre thick and are characterized by high liptinite contents. They are often referred to as needle coals because of their structure, which derives from a high algae content. They tend to be better developed near the Mist Mountain contact. Coals of this type generate large quantities of thermogenic methane at ranks of 0.6 to 1.0%. The liptinite maceral is not very micro porous so that they have lower adsorption abilities than other macerals. However the maceral is less brittle than vitrinite and tends to withstand deformation better. In areas where the Mist Mountain is below prospective depths the overlying Elk Formation, which contains a higher sand content than the Mist Mountain Formation, may well contain free gas in sandstones and adsorbed gas in thin coal seams.

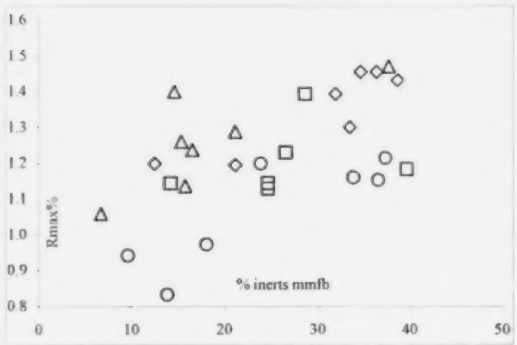


Figure 9: Variation in inerts content (mmfb) with rank.

Historical data

In 1939 the Minister of Mines Report states that in the Coal Creek Number 1 Colliery " a considerable amount of methane is given off this amounting to an average of 1250,000 cubic feet in 24 hours". Elsewhere in the report it states that ventilation was 74300 cubic feet per minute. The numbers suggest that the methane content in the mine air was upwards of 1%. McCulloch *et al.* (1975) indicate that there is an approximate empirical relationship between the amount of methane per ton released for a mature mine and the in-place gas content of the coal (Figure 10). The relation predicts that the in place gas content (cc/g) is 1/7th the gas emission/tonne of mined coal. In 1939 coal production in the East Kootenays was about 500 000

Table 5: Estimated gas composition data from Rice (1918).
Composition of gas in coal samples volume %
samples from working faces Coal Creek Colliery 1916
Coal Creek Crowsnest coalfield

sample	CH_4	CO_2	O_2	N_2	$CO_2/(CO_2+CH_4)$
17	64.1	1.4	1	33.5	2.1
18	24.6	0.9	4.4	70.1	3.5
19	27	1.2	3.2	68.6	4.3
20	15.8	0.4	1.2	82.6	2.5
21	0.3	1.6	20	78.1	84.2

tonnes and production from the Number 1 East Colliery, Coal Creek was 124616 tons (Newmarch, 1953). If this tonnage is assigned to the Number 1 mine and it operated for 300 days in the year then the predicted gas content is over 13 cc/g. The Number 1 seam (lowest in the section) was reported to be the gassiest seam mined. There are a number of reports indicating that the coal from the Coal Creek Collieries was gassy and dusty.

The Carbonado Colliery (6.5 Km up Morrissey Creek from the Elk River), which opened in 1902, is described as being very gassy and prone to outbursts. It was closed in 1909 after a number of serve gas outbursts. Other reports indicate that seams low in the section were very fractured and produce a lot of fine coal.

There is very limited public data on CO_2 concentrations in coals in the Crowsnest Coalfield. A report (Rice, 1918) provides some analyses. In 1916, five samples were collected from the working face in the underground Coal Creek Colliery and placed into sealed jars (Table 5). When the gas was analyzed it was apparent that all had leaked, however the CO_2 content may be estimated from the $CO_2/(CH_4+CO_2)$ ratio and it appears that except for one sample CO_2 contents were probably less than 5% (data are reported as cc per 100 grams equivalent to mole fractions). Based on the trace of the Bourgeau Thrust relative to the outcrop of the basin (Monahan, 2002), it appears that seams in the Mist Mountain Formation in the Crowsnest may not have been as close to carbonates in the overlying Bourgeau Thrust plate as seams in the Elk Valley Coalfield and may therefore have lower CO_2 concentrations.

Coal Deformation and implications for CBM production

The Crowsnest Coalfield is folded into a series of north trending anticlines and synclines, which generally have steep dipping west limbs and shallower dipping east limbs. Folds open to the south indicating less east west compression of the coalfield in that direction. They are contained in a number of north trending blocks defined by thrusts and normal faults. On the east, the major fault system is composed of the Erickson and Flathead normal faults and on the west it is the Lookout/Dominion thrust system. The folds reverse plunge through the basin, with the McEvoy Syncline in the south forming a distinct basin and the Coal Creek Syncline forming a basin under Fernie

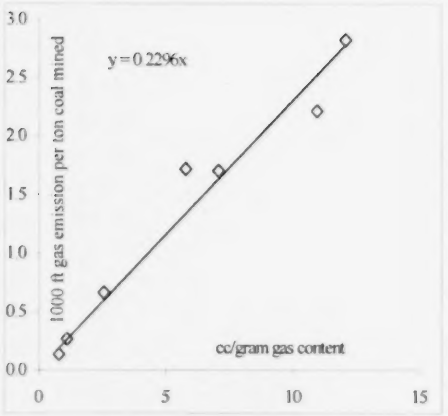


Figure 10: Relationship of gas released in underground mine and adsorbed gas content
plot derived from McCulloch *et al*. (1975)

Ridge. The map of Price (1961) indicates a number of plunge reversals for folds. It is not clear if these are related to a later phase of cross folding or controlled by changes in statigraphic thickness. Obviously if they are related to a later stage of cross folding then this could cause extension and improved permeability in areas where the cores of synclines or anticlines form culminations.

The Crowsnest Coalfield forms part of the Lewis thrust sheet, which in southeastern BC was transported between 140 and 200 kilometres at a rate of about 1.5 centimetres per year (Osadetz *et al*., 2003). Movement took place in the period from 74 to 59 million years as is indicated by profound cooling in the thrust block at about 75 million years (Osadetz *et al*., 2003). This movement is documented by analyzing the displacement on the thrust plane however there was also probably bedding plane slip within the thrust sheet that would over the estimated 7 kilometres thickness of the sheet (Osadetz *et al*. (2003) account for more displacement.

Some of this additional displacement is hidden in the Fernie Formation in that rocks below the Fernie Formation are more folded than the overlying Kootenay Group and fold geometries are offset (Price 1961). Additional displacement almost certainly occurred along coal seams. Bedding plane movement along seams will increase coal fragmentation and its amount will not be related to the degree of any subsequent folding. If the coal was maturing through high-volatile bituminous rank at the time of thrust displacement it would be very susceptible to bedding plane slip.

In-seam shearing related to Lewis thrust movement and not to folding produces fine coal and inhibits the formation of cleats or destroys those that have formed. It plays a key role in limiting permeability and causing production problems. It is therefore important to consider what factors might limit the amount of shearing in seams. Some examples of seams that may resist shearing

are:

- Thinner seams
- Seams rich in inert macerals or liptinite
- Seams that attain high rank before thrusting started
- Seams with higher ash content
- Seams with non clay rich hanging wall and footwalls.

There have been a number of studies of coal seam deformation in the northern part of the Crowsnest Coalfield. Norris (1965) studied A seam in underground A-North Mine at the north end of the coalfield. This seam is approximately 420 metres above the basal Balmer or 10 Seam in the Mist Mountain Formation. He describes the seam as being highly sheared with abundant shear surfaces and intrastratal folds. Joints tended to strike north or northwest with evidence of early minor extension faults cut off by renewed bedding plane slip. He does not directly discuss cleats or the degree of shearing in the seam but the impression is left that the seam is highly sheared and fragmented.

Bustin (1982) studied the lowest seam in the Mist Mountain Formation in a number of underground coalmines (Balmer North, Five Panel and Six Panel) at the north end of the Crowsnest Coalfield. In the Balmer North Mine, the best-developed cleats formed acute angles to bedding, striking northwest and dipping shallowly to the southeast. Cleat surfaces were polished and striated. Other cleat sets were measured but did not have a consistent orientation through the mine. Cleats in the Five and Six Panel mines are more consistent with a set striking north to northwest with a steep dip to the west. These cleats are sub perpendicular to bedding and trend parallel to the regional fold axis. All fractures and most cleats in the seam appear to have a tectonic influence, with surfaces polished and often showing evidence of shearing. However their orientations are not easily related to a regional stress field. Thrusting probably started with differential movement between the roof and floor (Norris, 1965) that disrupted earlier extension faults. As seam thickening and thrusting progressed exogenetic fractures with fold axis parallel trends and variable dips to the west developed in the coal.

Summary

The Crowsnest Coalfield is an area of 600 square kilometers underlain by the Jura-Cretaceous Mist Mountain Formation, which contains from 30 to 60 cumulative metres of high-volatile to low-volatile bituminous coal. The combination of area and cumulative coal guarantees a large resource of coalbed methane, which has been estimated at 12 Tcf. However outlining a resource is a far cry from defining a reserve. The coalfield forms part of the Lewis thrust sheet and has therefore had a protracted deformational history, which started with thrusting followed by folding in the late Cretaceous and continued with extension on north trending major faults in the Tertiary. The thrusting caused shearing within some seams that is unrelated to the amount to subsequent folding. This has probably limited permeability and generated fine coal that will make production more difficult.

Successful production will probably rely on understanding the interplay between deformation coal quality and location in specific structures. With these caveats in mind the more perspective area is where the Mist Mountain Formation is in the depth window of approximately 200 to 1000 metres. The Crown has clear title to the CBM in part of this area (Figure 1) and it is within this sub area that a more detailed assessment of the CBM resources has been made. The value of about 3 Tcf defines the size of a box within which hopefully reserves can be located.

A number of ideas relating structure coal quality and CBM are proposed that may help explorationists zero in on areas where reserves are located.

Acknowledgements

Bob Morris was kind enough to read the manuscript and correct some of the more obvious errors in the original draft.

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BRITISH COLUMBIA

NEWS RELEASE

For Immediate Release
2003EM0004-000284
March 25, 2003

Ministry of Energy and Mines

GOVERNMENT CREATES CERTAINTY FOR COALBED GAS OWNERSHIP

VICTORIA – The government has introduced new legislation that will create economic opportunities in B.C.'s heartlands by clarifying ownership of coalbed gas resources throughout the province, Minister of Energy and Mines Richard Neufeld announced today.

"The Coalbed Gas Act is an integral component of the government's Heartlands Economic Strategy and fulfils our throne speech commitment to open up coalbed gas resources throughout B.C.," said Neufeld. "Coalbed gas is an important new resource that offers tremendous economic potential for our province and will help ensure a secure, reliable energy supply for the future – one of the cornerstones of our new energy plan."

Prior to the Coalbed Gas Act, there was uncertainty about whether coalbed gas rights were legally owned by the owner of the coal rights or whether investors could gain access to the gas as a separate resource. The provincial policy, established almost 20 years ago, is that coalbed gas is a natural gas owned by the holder of natural gas rights. The Coalbed Gas Act enshrines that policy in legislation, providing the legal certainty needed to open up new investment and exploration opportunities.

"These legislative changes will unleash the potential of our vast coalbed gas resources by creating the stability needed for this industry to develop and succeed in bringing economic prosperity and opportunity to every region of our province," said Neufeld. "Our service plan commitment to generate $20 billion of cumulative investment in the oil and gas sector by 2008 is on track. Energy demand is rising and new sources like coalbed gas have the potential to diversify B.C.'s energy supply."

Coalbed gas, also known as coalbed methane gas, is found in coal seams in almost every coalfield across the province. There are an estimated 90 trillion cubic feet of coalbed gas in B.C. Although there is not yet any commercial production of coalbed gas in Canada, there are nine experimental projects underway in northeast B.C. and one in the southeast. An exploratory well has also been drilled on Vancouver Island.

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BRITISH COLUMBIA

INFORMATION BULLETIN

For Immediate Release
2002EM0013-000542
March 14, 2002

Ministry of Energy and Mines

CHANGES EXTEND BASE 9 ROYALTY AND CREATE NEW COALBED METHANE ROYALTY

VICTORIA – Changes to the petroleum and natural gas royalty and freehold production tax regulation introduced in the 2002 provincial budget mean a two-year extension of the eligibility for Base 9 royalty for conventional gas and a new royalty regime for coalbed methane.

The first change to the petroleum and natural gas royalty and freehold production tax regulation extends the eligibility period for acquiring lands for which the Base 9 royalty rate applies. Introduced in June 1998, the Base 9 royalty is a minimum nine-per-cent royalty on new production from tenure acquired between June 1, 1998 and Dec. 31, 2001, that is drilled within five years of acquisition. Without this change, lands acquired after Dec. 31, 2001 would have been subject to a minimum rate of 12 per cent (Base 12) royalty.

The change extends the Base 9 royalty eligibility by two years to Dec. 31, 2003, and makes the regulation retroactive to Jan.1, 2002.

The following chart shows the difference between the Base 9 and Base 12 royalty curves.

The second change to the regulation provides for a new royalty regime for coalbed methane, which reflects the unique development and production costs of this resource. It also provides the framework for the expeditious and orderly development of the industry. Effective March 1, 2002, the new regime:

- includes produced-water handling costs in the producer cost of service allowance to address the added water management costs;
- creates a royalty bank to collect excess allowance to be used against future assessed coalbed methane royalties;
- increases the marginal well adjustment factor threshold to 600,000 cubic feet per day from 180,000 cubic feet per day to address the lower production rates; and
- provides a $50,000 royalty credit for coalbed methane wells drilled within the next two years.

The new royalty regime is the result of a collaborative effort between government and industry over the past year. It will ensure that British Columbia's fiscal regime remains competitive with other jurisdictions, encourages coalbed methane development, and in turn increases direct revenue to the province. Developing coalbed methane will also create jobs in the oil and gas sector and diversify petroleum industry activity in all regions of the province.

-more-

Both changes are part of government's strategy to double oil and gas production by 2011, and generate $20-billion worth of cumulative investment in British Columbia's oil and gas industry by 2008.

-30-

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BRITISH COLUMBIA

Factsheet

2003EM0008-000536
May 30, 2003

Ministry of Energy and Mines

OIL AND GAS DEVELOPMENT STRATEGY FOR THE HEARTLANDS

Updated - June 9, 2003

SUMMER ROYALTY PROGRAM

Qualification Criteria:

A producer may deduct a summer drilling deduction amount from its total royalty payable to the province if

(a) the producer has one or more interests in a well and
(b) the well has a spud date after June 30, 2003 and before December 1, 2003, after March 31, 2004 and before December 1, 2004 or after March 31, 2005 and before December 1, 2005.

Where the following terms are defined:
"goods and service costs" means, in relation to a well, the costs incurred by the producer for goods and services directly related to the drilling of the well.
"well event" means all completions in a zone for a well with a primary product of natural gas.

Royalty Calculation:

The summer drilling deduction amount is, for each well referred to above, the lesser of the following multiplied by the producer's proportionate interest in the well:

(i) 10% of the goods and service costs attributable to the well.
(ii) $100,000.

Examples of Goods and Service Costs related to directly drilling a well:

BOP, Coring and Tong Services
Cementing and Stimulation Services
Camps
Drilling and Completion Tools and Services
Drilling Fluids & Chemical Suppliers
Drilling Mats
Equipment and Processing Manufacturers
Fabricators

Pipe and Drill Bit Manufacturers
Pipe Coating and Inspection Services
Production Testing
Rathole Conductor Contractors
Safety Services
Snubbing Services
Specialized Trucking Services
Supply and Rental Stores
Well Consultants
Wireline and Perforating Services

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Visit the province's Web site at http://www.gov.bc.ca/ for online information and services.

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OIL AND GAS DEVELOPMENT STRATEGY FOR THE HEARTLANDS

BC Ministry of Energy and Mines 2003 Royalty Modifications

FREQUENTLY ASKED QUESTIONS

Does Gathering Systems count towards the summer deduction?

No, PCOS is meant to be used for oilfields and pipeline construction.

"Well Depth" is defined as the vertical distance between kb and the top of the deepest productive 'zone' of the well. Can you define zone for me, ie: if we are in the lower Montney does the well depth end at the top of the Montney (upper Montney)? There could be many 'zones' in the Montney formation.

The OGC would evaluate the well and designate the pool(s) that had been encountered. Each pool would have a top and base of pay (This relates to "zone" in the deep royalty definitions). Using the Montney example, if all the pay intervals encountered were deemed to be in the same pool, the top of the zone would be the top of the pay. For the Deep Royalty if the Montney was deemed to contain several pools, the top pay of the deepest Montney "zone" would define the "well depth".

Does the Summer Royalty provide credit towards recompletion costs?

No, only towards the Drilling and Completion costs of Wells spud after June 30, 2003 and before December 1, 2003; after March 31, 2004 and before December 1, 2004; and after March 31, 2005 and before December 1, 2005.

How does the OGC determine if a well is suspended?

A well's status must be formally altered with the 'BC 11 form' by the producer in order for a well to be changed from active status to suspended or abandoned status.

Further, Section 43 of the *Drilling and Production Regulation* requires that a "Notice of Commencement or Suspension of Operations" (BC-11 form) be submitted within 7 days following the date a well is placed on continuous production, suspension or service.

Numerous inactive wells are currently recorded by the OGC as having a status of "active" or "testing". The OGC plans to change the status of these wells to "suspended". The criteria used to identify a suspended well will be based on the following;

" a UWI which has not produced for 12 consecutive calendar months, which may or may not have previously produced."

Should an operator have reason why an inactive well, as defined above, should not have a status change to "suspended", they should contact the OGC by August 31, 2003.

Current well/UWI status, as recorded by the OGC, may be reviewed from the **well index** available from the OGC web site. The **well index** is available, in a number of different formats, from the following address;

www.ogc.gov.bc.ca

under "Statistics and Rig Activity" click "Data Downloads"

Do Oil Wells qualify for the Summer Royalty program?

Yes, Oil Wells and Natural Gas Wells are eligible for the Summer Royalty program.

TITLES-03-03 ***(Supercedes Information Letter EMD99-05)***

TITLES DIVISION

Subject: Coalbed Gas Rights

Definition of Coalbed Gas:

Coalbed Gas is natural gas colloquially referred to as coalbed methane. In British Columbia coalbed gas is defined as all substances:

(a) That can be recovered to the surface through a wellbore from subsurface coal deposits and any reservoirs in communication with the coal deposits, and
(b) The volume of which, if measured at the surface immediately following that recovery, would be measured as a gas.

Coalbed Gas Ownership:

The *CoalBed Gas Act* was given Royal Assent on April 10, 2003 and confirms that coalbed gas is natural gas owned by the holder of natural gas rights. Rights to Provincial coalbed gas are conveyed by petroleum and natural gas tenures issued under the *Petroleum and Natural Gas Act*.

Request for Posting of Provincial Coalbed Gas:

Persons wishing to obtain rights to coalbed gas may nominate parcels for inclusion in a competition for petroleum and natural gas rights. See Information Letter "Crown Disposition Dates -Titles-03-02" for details on postings and nominations. Requested parcels may be configured to include only coal bearing zones. Requests for rights in areas outside the northeast region of the Province may require more processing time than indicated in information letter Titles-03-02 to allow for ownership research and consultation requirements.

Freehold/Private Coal Rights:

In certain areas, and for a limited period of time, freehold or private coal owners may have an option to acquire coalbed gas rights from the Province. Freehold coal is primarily located on Vancouver Island and in the Kootenays. Contact Mrs. Kim Stone, Coal Administrator, Titles Division, Ministry of Energy and Mines at 250-952-0567 for specific details and please visit our website to view information letter TITLES-03-06 at: http://www.em.gov.bc.ca/Subwebs/landsale/Infoletters/petitles/TITLES-03-06.htm

Royalty and Freehold Mineral Tax:

For information regarding coalbed gas royalty, freehold mineral tax, qualifications for low productivity gas assessments and other royalty programs, please visit the ministry internet address: http://www.em.gov.bc.ca/subwebs/oilandgas/royalties/newtargeted.htm.

Exploration, Drilling and Production:

Coalbed gas exploration drilling and production activities are regulated by the Oil and Gas Commission, under the provisions of the legislation governing petroleum and natural gas.

For Further Information Contact

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Victoria, BC V8W 9N3
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Gerald German
Executive Director
Titles Division

October 1, 2003

MPCAA/B/C

TITLES-03-06 (Issued September 23, 2003)

TITLES DIVISION

RE: DISPOSITION OF CROWN PETROLEUM AND NATURAL GAS RIGHTS IN FREEHOLD COAL AREAS

The Ministry of Energy and Mines is currently considering direct award of Crown petroleum and natural gas rights within specific coal formations to the owners of freehold coal lands in British Columbia pursuant to s. 72(2) of the *Petroleum and Natural Gas Act*. These lands are primarily on Vancouver Island and the Kootenay region.

This opportunity to obtain Crown petroleum and natural gas rights is being provided to freehold coal owners in an effort to stimulate the development of coalbed gas. Rights will be issued in the form of a drilling licence and will be subject to the provisions of the Petroleum and Natural Gas Act Drilling Licence Regulation. The opportunity to acquire drilling licences will remain open for a five-year period, but the freehold coal owners must exercise the option on at least twenty percent of their lands each year.

The provision of this opportunity is in keeping with the *Coalbed Gas Act* and will be available only on freehold coal lands. The opportunity will only be available in freehold coal lands in which the petroleum and natural gas rights are held by the Crown. The opportunity will not be extended to lands covered by Crown issued coal tenures.

Details of any drilling licence issued will be announced at the time of issuance.

For further information contact:

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Gerald German
Executive Director
Titles Division

OIL AND GAS COMMISSION

September 10, 2003 **INFORMATION LETTER #OGC 03-19**

SUBJECT: **Coalbed Methane Plan (CBM) Approvals Under Section 100 of the *Petroleum and Natural Gas Act***

To Industry Clients:

The *Petroleum and Natural Gas Act* (PNG Act) has been amended to facilitate the decision-making process for coalbed methane projects.

A full cycle CBM project lends itself to staged approvals consisting of an initial evaluation plan approval; followed by a development plan approval and then a full-scale production plan approval.

Effective July 21, 2003, the OGC will use the following classifications for CBM developments:

i) **CBM Evaluation Plan** consists of the drilling, completion and testing of the initial small group of wells. Typically, this comprises of three to six wells, intended to demonstrate the technical feasibility of a particular CBM operation, with respect to drilling, completion, dewatering and recovery of natural gas from one or more coal-bearing formations. CBM Evaluation Plans will be approved under Section 100(1)(b) of the *PNG Act*.

ii) **CBM Development Plan** consists of the drilling, completion, testing and production of a limited number of wells. This is typically in the order of 20 to 40 wells to demonstrate the commercial viability of CBM production in an area and from the formation(s) from which the technical recovery of natural gas has been demonstrated, or is otherwise considered with reasonable certainty to exist. CBM Development Plans will be approved under Section 100(1)(a) of the *PNG Act*.

iii) **CBM Production Plan** consists of drilling, completion and production of wells for a full-scale commercial natural gas recovery operation in an area and from the formation(s) which commercial recovery of CBM has been demonstrated. CBM Production Plans will be approved under Section 100(1)(a) of the *PNG Act*.

The new classifications will enable appropriate conditions for the particular CBM plan and the stage of exploitation to be established in the approvals. Experimental scheme approval will no longer be applied to full-cycle commercial exploitation of CBM.

The OGC will continue to work closely with the proponents, stakeholders and First Nations, to implement plans that are acceptable to the concerned parties. Proponents may benefit by matching public consultation requirements to each type of plan, and as a result, be able to respond appropriately to stakeholder and First Nations' concerns.

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Specifically, some of the changes are as follows:

- Well spacing for CBM Production Plans will be one well per quarter section on private or leased agricultural Crown land.

- The CBM Evaluation Plan and the CBM Development Plan approval will each convey a three-year confidentiality period for well data under section 57(4) of the Drilling and Production Regulation. Confidentiality of data from wells within approved CBM Production Plans will be determined by the individual classification of each well.

- Flaring, once a well has been completed, will normally be approved only within a CBM Evaluation Plan and will be limited to a maximum of 1.5 $10^3 m^3/d$ per well for no longer than three months. Flaring will be minimized and specifically approved in a CBM Development Plan. Flaring will not normally be allowed in a CBM Production Plan.

For further information, please contact:

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Original Signed
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Canada BRITISH COLUMBIA

NEWS RELEASE
COMMUNIQUÉ

For Immediate Release
2003TNO0029-000872
Oct. 4, 2003

Treaty Negotiations Office
Indian and Northern Affairs Canada
Ktunaxa Kinbasket Tribal Council

$1 MILLION FUNDING TO SPUR FORESTRY AND COALBED METHANE DEVELOPMENT

CRANBROOK – The Honourable Robert Nault, Minister of Indian Affairs and Northern Development, and the Honourable Geoff Plant, Attorney General and Minister Responsible for Treaty Negotiations of British Columbia, today announced joint funding of more than $1 million for a forestry and a coalbed methane economic development project with the Ktunaxa Kinbasket Tribal Council (KKTC).

"Through these initiatives, the Ktunaxa Kinbasket Tribal Council is once again demonstrating a commitment to the future of the community, as well as to the B.C. economy," said Minister Nault. "I am encouraged by the dedication the Ktunaxa Kinbasket Tribal Council shows its members through engaging in partnerships, resulting in new opportunities and business developments."

"The Ktunuxa Kinbasket Tribal Council's increased engagement in the forestry and coalbed methane sectors – in both business-development and provincial planning processes – is expected to provide increased jobs and business opportunities for the First Nation and the entire Kootenay region," said Minister Plant. "These projects are part of our government's continued efforts to materially improve the lives of aboriginal people in B.C."

A key planned outcome of the forestry project, the Community Forest Pilot agreement, will provide the KKTC with a five-year tenure of approximately 6,000 cubic metres of wood per year.

"While the licence will be relatively small, it will give us tenure and a foothold in the forest economy of southeastern B.C." KKTC administrator Kathryn Teneese said. "On a very fundamental level, the various components of these economic development projects are a first small step toward increasing our human and technical capacity which are so critical for everything we do. With these projects we intend to build effective and collaborative approaches in our working relationships with the resource sector."

The Province of British Columbia is contributing a total of $586,000, and the Government of Canada is contributing $548,378 to these two projects. The KKTC, which represents five First Nations in southeast B.C., will receive this funding over a three-year period. Expected outcomes for the projects include two or more partnerships; three or more new businesses established; and the creation of 19 new full-time and up to 60 part-time jobs.

Since April 2002, Indian and Northern Affairs Canada has invested $11 million to support 88 projects in British Columbia. Today's announcement further demonstrates the Government of Canada's commitment to work with First Nations and contribute to strengthening aboriginal entrepreneurial and business expertise while supporting strong, self-sufficient First Nation communities.

-more-

The $40-million provincial Economic Measures Fund is managed by the provincial government's Treaty Negotiations Office. It creates new opportunities for First Nations' participation in the economy, including activities related to oil and gas, shellfish aquaculture, tourism, forestry and the 2010 Winter Olympic and Paralympic Games. Funds are available for B.C. First Nations inside and outside of the treaty process. To date, 113 projects worth a total of $25 million have been approved.

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This release is also available on the Internet at http://www.inac.gc.ca and http://www.gov.bc.ca/tno

2 backgrounder(s) attached.

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Ktunaxa Kinbasket Tribal Council
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Visit the province's Web site at www.gov.bc.ca for online information and services.

Guidelines for Coalbed Methane Projects in British Columbia

OIL AND GAS COMMISSION

October 21, 2002

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Introduction

The Government of British Columbia wishes to encourage development of the province's coalbed methane[1] (CBM) resource. To demonstrate that support, the Ministry of Energy and Mines (MEM, or the Ministry) is implementing a strategy to establish CBM as a clean, environmentally safe energy source that can be developed to service local, domestic, and export markets.

Despite a very large CBM potential, estimated at in the order of 90 Tcf, commercial production has yet to be initiated in British Columbia. In comparison, 7 percent of annual natural gas production in the United States is derived from CBM.

Recently, there has been increased provincial interest and activity, with 8 CBM schemes approved for development in the East Kootenays and Northeastern BC and one well on Vancouver Island. As a result, the Oil and Gas Commission (the OGC or the Commission) has decided to issue *Guidelines for Coalbed Methane Projects in British Columbia.*

Purpose of the Guidelines

These guidelines are intended to clarify for project proponents and operators the existing regulatory requirements for CBM developments in the province. CBM requirements have been accommodated within the prevailing legislation and regulations for conventional petroleum and natural gas resources, notably the *Petroleum and Natural Gas Act* (PNG Act) and the *Drilling and Production Regulation* (D&P Regulation). In the future, regulations, policies, and procedures may be changed to better allow for the specific needs of CBM projects, as experience is gained.

The guidelines focus primarily on how CBM projects will be treated differently from conventional natural gas developments. For the vast majority of requirements that are identical to those for conventional gas, CBM proponents and operators should refer to the OGC website (www.ogc.gov.bc.ca), the *Oil and Gas Handbook* available from Crown Publications Inc. (www.crownpub.bc.ca) and other relevant sources (e.g., the *Maximum Disturbance Review Criteria Operating Code*). Commission staff can provide further guidance on these requirements, including the application and approval process for wells and other facilities.

The Nature of CBM Development

Compared to conventional natural gas production, CBM projects have unique characteristics. Coal seams may demonstrate sufficiently low permeabilities such that they must be hydraulically fractured or stimulated to enable their dewatering and the production of gas. Effective gas recovery usually requires a number of wells to dewater the coal seam, reduce the formation pressure, and produce the CBM. The low-pressure gas is then gathered and compressed for delivery to the sales pipeline.[2]

CBM projects are normally phased, with the drilling of a few pilot wells to test potential production followed by a larger scale development that may reach tens to hundreds of wells. To ensure a commercially viable project, proponents and operators must have a clear understanding of the regulatory requirements at all stages of project development from the initial identification of a CBM prospect through project planning, drilling, production, and abandonment and site restoration.

[1] See the Glossary in Attachment 3 for a definitions of the terminology used throughout this document.
[2] For more information on CBM production, see BC Ministry of Energy and Mines, *Coalbed Methane in British Columbia.*

OBJECTIVES OF CBM REGULATION

The OGC recognizes the unique nature of CBM, the challenges faced by project developers, and the unproven commercial viability of development in British Columbia. CBM projects are usually characterized by high up-front capital expenditures, relatively high operating costs, and production rates that may be lower than many conventional natural gas projects. Consequently, where warranted and prudent, the Commission will be flexible in accommodating CBM developments to recognize these unique characteristics.

At the same time, it is recognized that, as CBM projects grow, they can have significant implications for the environment, local community, and worker and public safety. Existing policy and regulations, including those under the D&P Regulation, *Oil and Gas Waste Regulation*, and *Waste Management Act*, are designed to address such matters. In addition, Commission staff are willing to work closely with proponents and operators to help them gain a clear understanding of the regulatory requirements as they develop and implement an effective program for managing environmental and community impacts.

Overall, the OGC objective is to regulate CBM activity in a manner that will facilitate its development in the province, while ensuring protection of the resource, the environment, workers, and the public. That is, the Commission is seeking to develop regulation that balances the interests of all stakeholders.

ONGOING COMMUNICATION WITH THE COMMISSION

It is recommended that CBM proponents contact the OGC as early as possible when planning and developing their projects to allow time to confer on technical aspects, waste management, environmental and community impacts, public consultation, and other key matters. This contact should continue throughout the planning, development, and production phases, with the proponent or operator providing up-to-date information on the project's progress and schedule. Only through ongoing communication can the Commission fully understand a CBM project and regulate it appropriately.

OGC staff specializing in the various areas described below are listed in the Contacts in Attachment 1. For general information on CBM policy in British Columbia, proponents and operators should contact MEM's New Ventures Branch (see General CBM Policy contact).

STRUCTURE OF THE GUIDELINES

These guidelines are organized by topic area as follows:

- Geophysical exploration;
- Well approvals
- Drilling and well servicing;
- Gathering system and pipelines;
- Production; and
- Abandonment and Reclamation.

Figure 1 provides a flowchart of the Commission's regulatory process for CBM projects.

Figure 1: Oil and Gas Commission Regulatory Process for Coalbed Methane Projects

[attached to end of paper]

Geophysical Exploration

All exploration or seismic operations in British Columbia are authorized under Part 4 (Geophysical Exploration) of the PNG, with requirements specified in the *Geophysical Exploration Regulation*. Operations must also comply with provisions of the *Forest Practices Code of British Columbia Act*.

Companies wishing to undertake a geophysical exploration program are required to obtain a Geophysical Licence from the OGC's Applications and Approvals Branch. For conventional petroleum and natural gas operations, an Application for Approval of Geophysical Exploration and an accompanying Timber Harvesting and Field Assessment are submitted to the Branch, which then initiates a multidisciplinary review of the proposed program. Consultation must take place with landowners, occupants, and trappers, and with the broader public and local government within a specified radius (see *Public Involvement Guideline*). Following the review process, the Commission issues a Letter of Approval, including any necessary conditions on the seismic activity.

Geophysical exploration requirements are essentially the same for CBM and conventional gas projects. The key differences are that CBM development is likely to be scattered throughout the province, and that the public is unacquainted with coalbed methane and its impacts. Therefore, companies may be required to conduct enhanced consultation with landowners and the public in order to inform and educate them with respect to CBM (see further under Well Approvals).

As with conventional gas development, the OGC provides a single-window review of geophysical exploration programs, with referrals to the regional/district offices of the Ministry of Energy and Mines, Ministry of Forests, Minister of Water, Land and Air Protection, and other agencies. The only exception occurs for projects that are located on Agricultural Land Reserve lands outside of the Peace River and Northern Rockies Districts, which must obtain a separate approval from the Land Reserve Commission.

Companies should refer to the *Geophysical Exploration Regulation* and Section 4 of the *Oil and Gas Handbook* for information on minimum drilling distances from structures and residences, licences to cut, stream crossings, construction requirements, reclamation, and other matters. The landowner's consent must be secured, through a negotiated agreement, before a seismic operation can be carried out on private property (see *Seismic Operations and the Landowner* and the discussion of Surface Access below).

For companies that are unfamiliar with oil and gas exploration in BC, it is recommended that they contact the Applications and Approvals Branch (see Geophysical Exploration under Contacts) to receive further guidance on the regulatory requirements.

Well Approvals

Petroleum and Natural Gas Rights

Provincial Rights

Most of British Columbia's petroleum and natural gas rights are owned by the province, except in areas of early settlement such as Vancouver Island and the Fraser Valley where the surface landowner owns the subsurface rights. The Ministry of Energy and Mines' Titles Branch is responsible for issuing and administering provincially owned oil and gas tenures.

The process for acquiring rights from the Crown is no different for CBM than for conventional natural gas, since subsurface petroleum and natural gas tenures also carry the rights to any coalbed methane in the area. Companies wishing to acquire the rights to specific areas request that they be included in one of the Titles Branch's monthly sales. Once all requests have been received for a specific sale, MEM refers them to First Nations, local governments, and other agencies for review and comment. Following a review period of approximately 4 weeks, the returned comments are collated and significant concerns may be expressed as conditions of the tenure document. For locations outside Northeastern BC, additional processing time may be required for the Ministry to research the subsurface ownership to determine the extent of Crown rights in the area of interest (particularly on Vancouver Island).

A public tender notice is then published in local newspapers and trade journals, with details provided in the BC Gazette and on the MEM website. This notice includes the geographic location of the parcel, the length of time tenure will be issued for, the annual rent, and specific conditions with which the successful bidder must comply. The sale is held on the scheduled date and companies submit sealed bids. Tenure is awarded to the company with the highest reasonable bid.

There are three types of tenure agreements used in the province:

- Permits carry an obligation to conduct exploration.
- Drilling licences convey the exclusive right to drill wells in a defined area.
- Leases provide exclusive drilling rights and allow production.

Parts of permits and drilling licences may be converted to leases if all obligations have been met. Typically, agreements run for 3 to 10 years, and can be renewed or extended if certain conditions are satisfied.

Private (Freehold) Rights

Privately held petroleum and natural gas rights exist throughout British Columbia, but are mainly concentrated in early settlement areas. In the late 1800s and early 1900s, the province included petroleum and natural gas rights with some grants of land.

It is a CBM proponent's responsibility to identify all holders of private rights in the area in which geophysical exploration, drilling, and/or production are to take place. Private rights may be identified through research in the appropriate Land Titles Office for the region. Proponents should also check with the Titles Branch for information on the area of interest.

The provincial government recognizes the need to better understand the picture of subsurface rights ownership in BC. As a result, MEM is in the process of initiating a major subsurface title research project. This is a significant undertaking and the project will be implemented over 5 years, with an initial focus on Vancouver Island.

Surface Access

The *Petroleum and Natural Gas Act* (Part 3) provides for the entry, occupation, or use of publicly held land in order to explore for, develop, or produce petroleum and natural gas in BC. To secure access to private land, the company must approach the landowner, usually through a land agent, and negotiate an agreement called a Surface Lease. A Surface Lease allows the company to enter onto the land to drill a well or construct and maintain any above ground structures, in exchange for a rental payment that must be renegotiated every 5 years. The requirements for surface leases and pipeline right of ways are described in *Surface Rights in British Columbia: A Guide to the Legislation and Regulations for the Oil and Gas Industry*.

Where an agreement cannot be reached, the company may apply to the Mediation and Arbitration Board for a Right-of-Entry Order under section 16 of the PNG Act. A hearing will be held to attempt to mediate an agreement between the parties. If that fails, a Right-of-Entry Order may be issued allowing the company entry in return for compensation to the landowner for loss or damage caused.

A company must obtain either a Surface Lease or Right-of-Entry Order, to be filed with the Registrar of Land Titles, before entering onto private land.

Experimental and Natural Gas Schemes

Section 100 of the PNG Act allows for the approval of special schemes that involve "the experimental application of oil field technology". An experimental scheme, as defined by the D&P Regulation, is one that uses "methods that are untried or unproved". Experimental schemes offer the benefits of flexible well spacing and an extended period for confidentiality of well data (see Well Spacing and Site Size and Data Reporting and Confidentiality).

Since coalbed methane development is new to the province, and CBM wells have uncertain lives and gas production profiles, all project applications submitted before December 31, 2003 may be approved as experimental schemes. An operator can apply to the OGC for an experimental scheme covering a continuous block of land, provided that the petroleum and natural gas rights for the area have been secured. The Commission then publishes a notice of the application in the BC Gazette. Over a period of about 3 weeks, any potentially affected party having surface or subsurface concerns with the application can provide written comments to the OGC, which may result in conditions being attached to the approval. The Commission approval stipulates the area covered by the experimental scheme, requirements for flaring and data reporting, and other terms and conditions (see Data Reporting under Production).

Recent revisions to the PNG Act have expanded Section 100 to provide for schemes for the development or production of natural gas in addition to experimental schemes. Regulatory revisions are now being drafted to support the revised Act. It is anticipated that as of January 1, 2004, CBM project applications may be approved as schemes for the development or production of natural gas. The approval process will be similar to that outlined above for experimental schemes.

Scheme approvals for CBM projects, either as experimental or natural gas schemes, may waive the spacing requirements for wells. The OGC's intention is to waive the spacing requirements for schemes approved for CBM development and production unless project-specific conditions dictate otherwise. The removal of the spacing requirements allows the scheme operator to locate wells as required to optimally develop the project.

Proponents having no experience with schemes are encouraged to make early contact with the Commission's Engineering and Geology Branch (see Experimental Scheme contact).

WELL AUTHORIZATIONS

Section 15.6 of the D&P Regulation requires a Well Authorization (WA) for every gas well drilled in British Columbia. Proponents must apply to the Commission for a WA and pay a fee of $8,400 per well. In the case of a CBM experimental scheme, the proponent must separately apply and receive approval for each well drilled in the scheme.

The OGC currently has 3 pilot projects underway to test general development permits, which involve a review and approval in principle of a company's overall plans for the development of an area. CBM projects would likely be good candidates for this kind of project-based review process. After the 2002/03 winter drilling season has been completed, the pilots will be reviewed and a decision will be made regarding the use of general development permits.

Pre-application Requirements

Before a proponent can submit a WA application, several pre-application criteria must be met:

- The company must be registered with the BC Corporate Registry in the Province of British Columbia or be incorporated under the laws of Canada. (Contact the Registrar of companies at 250-397-5101.)
- A drilling deposit (minimum of $7,500) must be submitted to the Ministry of Energy and Mines as security for the proper drilling, control, completion, suspension, abandonment, reclamation, and restoration of the well and well site.
- Comprehensive general liability insurance, with a limit of $1 million naming Her Majesty the Queen and the Commission as the insured, is required to hold a Crown land surface tenure document.
- A Master Licence to Cut must be obtained for each forest district in which the proponent will harvest Crown timber. This includes all timber on Crown land whether it is merchantable or not, and also covers any Timber Reserve Areas where the Crown holds the timber rights even though the land is privately lowed. (Contact the Commission.)

The Master Licence to Cut sets out the conditions and utilization standards by which the proponent may harvest timber in the particular forest district. Once a licence has been obtained, cutting permits are issued under its terms as part of the approval documents for individual applications. If timber harvesting occurs within a woodlot, the woodlot owner is responsible for obtaining the cutting permit from the Ministry of Forests.

Application and Approval Process

The application forms and checklists required for a WA can be found on the OGC website (www.ogc.gov.bc.ca/formschecklists.asp). Applicants who are new to oil and gas development in British Columbia are strongly urged to make an initial visit to the Commission's Fort St. John office, where Applications and Approvals Branch staff (see Well Authorization contact) can guide them through the application process. At the same time, OGC staff can advise the proponent of the various agencies, First Nations, and stakeholders that must be contacted as part of the particular approval.

When a proponent submits an application, it is checked for completeness and then reviewed for technical merit as well as potential impacts on land, fish and wildlife habitat, forest resources, stakeholders, archeology, and First Nations. All applications received by the OGC are screened as being "simple", "normal", or "complex". Depending on the project, a CBM application may require a timber harvesting and field assessment, fisheries and habitat assessment, archeological assessment, First Nations consultation, and public consultation. After the consultations and

review have been completed, the Commission may issue an approval with any necessary conditions attached.

There is a single-window approval process where reviews are conducted by interdisciplinary OGC staff, with referrals as needed to other agencies. For applications that are located in Agricultural Land Reserve lands outside of the Peace River and Northern Rockies Regional Districts, a separate approval must also be obtained from the Land Reserve Commission (LRC). Currently, negotiations are underway to streamline the OGC and LRC processes and to enhance the Commission's one-window approach.

Public Consultation

The proponent must identify all parties who may be impacted by a CBM scheme, and must consult with them at a level reflective of the potential impact. The OGC's *Public Involvement Guideline* provides guidance on responsibilities for public consultation, consultative tools and timing, and documentation of information. In addition, minimum distance requirements from the well site are specified for personal consultation and broader notification (see the *Maximum Disturbance Review Criteria*). Proponents are encouraged to complete their public consultation process before making a WA application, to ensure better planning and relationships with landowners, First Nations, and other affected parties.

It is recognized that the public is unacquainted with coalbed methane, and that the impacts of CBM projects can differ significantly from those of conventional oil and gas development. In particular, the longer lives of CBM wells (10 to 40 years compared to 3 to 25 years for conventional gas), and the magnitude of disturbance that can be caused by multiple wells in a given scheme, require due diligence on the part of applicants to inform and educate. The OGC is empowered to request, on a case-by-case basis, an enhanced consultative process. Proponents can expect to conduct enhanced public consultation where projects are located outside Northeastern BC or close to populated centres.

Because of the phased nature of CBM projects, the proponent will not know the ultimate scale of a development until some pilot wells have been tested. When consulting prior to an application, the proponent should inform First Nations, stakeholders, and the public of the planned impacts of the project consistent with the most reliable information available at the time. Subsequently, as development proceeds, affected parties (as well as the Commission) should be kept informed of its progress and updated on the project's scale, land and water disturbance, and other impacts.

First Nations

Proponents are encouraged to consult with local First Nations on their CBM projects, including associated economic development opportunities. OGC and MEM staff will assist in identifying affected First Nations.

Consultation for potential infringement of aboriginal or treaty rights is the responsibility of government through the Commission. In Northeastern BC, Memoranda of Understanding (MOUs) and Agreements have been signed with Treaty 8 First Nations. These consultation agreements establish a time-limited review process for First Nations to provide comments to the Commission on applications referred to them. Based on the consultations and the degree of potential infringement, applications may be approved with measures to minimize impacts on First Nations interests. Copies of several MOUs can be viewed at www.ogc.gov.bc.ca/firstnations.asp#mou.

Outside the Northeast and for non–treaty First Nations, the OGC and MEM use the evolving British Columbia First Nations Consultation Guidelines to consider aboriginal rights and title in the decision process for WA applications. The guidelines are available from the Treaty Negotiation Office website at www.gov.bc.ca/tno/consult/.

In addition to the above consultations, MEM's Aboriginal Relations Branch conducts information sessions with First Nations to inform them about CBM and identify appropriate contacts for further dialogue. These sessions, which have already taken place in many areas of the province, are designed to initiate a relationship with First Nations for exploring potential impacts and opportunities associated with CBM development.

Well Classification

A Well Classification will be assigned as part of the WA process. Where there is an approved experimental scheme, every well drilled in the scheme will automatically be given experimental status. If the proponent has not applied for and received approval for an experimental scheme, then the Commission will classify each CBM well as either a development well, an exploratory outpost well, or an exploratory wildcat well (section 14.1 of the D&P Regulation). For these classifications, well data will remain confidential for 2 months, 6 months, and one year, respectively, from the date of release of the drilling rig (section 57.4). All CBM wells will be identified by "CBM" in the well name.

TEST HOLES

In addition to authorized wells, the *Petroleum and Natural Gas Act* allows for the drilling of "test holes" to obtain information about petroleum and natural gas resources. A test hole cannot be produced, but may be flow tested. An operator wishing to drill one does not require petroleum and natural gas tenure, but will need surface access for any entry onto private land.

Section 18 of the *Drilling and Production Regulation* sets out the requirements for test hole authorizations. All information from test holes is granted confidential status for 3 years after the rig release date. Test hole application forms and checklists are available from www.ogc.gov.bc.ca/formschecklists.asp.

The OGC will consider a well authorization that would have the effect of "converting" a test hole to a well. As with any natural gas well, the operator must hold natural gas tenure to apply for a well authorization. An applicant will be required to satisfy all relevant requirements of the PNG Act and D&P Regulation that pertain to wells, in order for a test hole to be considered for conversion. The applicant will also be required to pay the WA application fee.

Drilling and Well Servicing

Well Spacing and Site Size

British Columbia's *Drilling and Production Regulation* (section 10.1)) requires one section, or approximately 260 hectares (640 acres), for each conventional natural gas well drilled (equivalent to one well per square mile). The target area for a conventional well excludes a 250 m setback from the boundaries of this normal spacing area (section 10.2). Conventional gas wells should not be spaced so close together that they compete for drainage of gas, but also not so far apart to prevent all of the gas reserves from being recovered.

CBM wells, on the other hand, typically benefit from closer spacing (e.g., 2, 6, or 8 wells per square mile), which can work to reduce the formation pressure, increase the methane desorption, and optimize ultimate gas recovery. The approval for an experimental or natural gas scheme under section 100 of the PNG Act allows flexibility in both the spacing of wells and the determination of the setback. Therefore, with a scheme approval, an operator will be allowed to drill wells within the scheme area to any density, subject to a reduced setback of 100 m.

For standard drilling operations, a conventional gas well typically requires a surface lease area measuring 120 by 120 m (1.44 hectares). Larger areas may be required for rigs to conduct directional, deep, or underbalanced drilling.

Because CBM wells are shallower than conventional gas wells, smaller rigs and surface areas may be used, resulting in a smaller footprint. During drilling, the area must only be of sufficient size to safely accommodate the drilling rig and all other equipment needed on the site for well development.

The OGC will consider reduced site sizes for CBM wells on a case-by-case basis, depending on the drilling and other equipment used. Lease size must be commensurate with spacing for maximum equipment requirements. Operators are encouraged to use good judgment and design their operations to leave a smaller footprint.

The Commission continues to work with the Workers Compensation Board (WCB) to determine minimum safe separation distances between equipment on CBM well sites. It is anticipated that standards will be developed incorporating reduced separation distances once the initial CBM projects demonstrate safe operations with such distances.

CBM is generally a sweet gas, consisting of methane and small amounts of carbon dioxide and nitrogen. US experience with CBM operations indicates no danger from hydrogen sulphide or sour gas, as is present in conventional natural gas. Given the lower volumes from CBM wells and the negligible risk of sour gas, it may be possible to grant reduced distances between well sites and roads.

Surface Casing, BOP, and Equipment Spacing[3]

The PNG Act (section 96.1.1) calls for "adequate measures to confine petroleum, natural gas, or water to its own stratum and to protect any coal seam or other mineral or workings in it from injury." Basically, to ensure the safety of workers and the public, the operator must be able to control a gas well at all times in all operations. This gives rise to requirements for surface casing, Blowout Prevention, and spacing of other equipment from the well.

For the drilling of a conventional gas development well up to 1850 m, a full Class A Blowout Preventor (BOP) stack with a pressure rating of 14,000 kPa is required. Surface casing must be set at least 25 m into competent formation in accordance with good oilfield practice at a depth

[3] More detailed requirements are provided in Attachment 1.

sufficient to provide a competent anchor for blowout prevention and to ensure control of anticipated pressures. The surface casing must have cement in the annulus along its full length to the surface.

Reduced surface casing, blowout prevention, and equipment spacing will be considered for CBM wells in some instances because of their lower pressures. In all cases, the ability to control anticipated pressures must be assured and all drinking water strata must be isolated.

Proponents will be expected to conform to conventional well requirements in areas lacking subsurface information. In areas where a reasonable understanding of the subsurface conditions exists, the proponent may request relaxed BOP and surface casing requirements. Operators contemplating undertaking CBM developments are urged to contact the OGC (see Surface casing/BOP contact) early in the planning process to establish surface casing and BOP requirements.

In all cases, the operator is required to conform to the Workers Compensation Board (WCB) requirements with respect to wellsite equipment spacing (*Workers Compensation Act*; *Occupation Health and Safety Regulation*, Part 23: Oil and Gas). As mentioned in the Well Spacing and Site Size section, the Commission continues to work with the WCB to develop specifications for reduced equipment separation distances that will be suitable for CBM projects.

Currently, for any reductions from full adherence to the D&P Regulation, the operator must contact the WCB (see Worker Safety contact) to ensure compliance. All drilling programs should be designed and carried out by qualified and competent personnel.

Rig Standards[4]

In some cases, CBM wells may be drilled using rigs and crews that are normally engaged in water well drilling or mineral coring. The OGC requires that both the equipment and personnel employed in a rig be capable to do the work of drilling a gas-producing well. Operators contemplating undertaking CBM developments are urged to contact the Commission (see Equipment Spacing/Rig Standards contact) early in the planning process to confirm rig and crew acceptability.

Samples, Logs, and Cores

For conventional gas wells, samples must be taken at 5-metre depth intervals over the entire wellbore and forwarded to the OGC (section 52.1 of the D&P Regulation). There is a minimum requirement for a gamma ray log and a resistivity and porosity log to be taken before the well is completed, suspended, or abandoned (section 53.2). Core analysis and tests performed either on the wellbore or on any samples obtained during drilling are generally left to the operator's discretion, with a copy of the results forwarded to the Commission. However, OGC staff may request that any well log, core analysis, drill-stem test, or other testing and analysis be performed on a gas well during its producing life (section 53.1).

Because CBM wells are drilled in tighter spacing than conventional gas wells, operators will likely make requests for logging and sampling waivers. The Commission will be flexible in determining which wells in a CBM scheme require the submission of samples, an open hole logging suite, cased hole logs, or no logs (complete logging waiver).

After a CBM scheme has been approved, the operator should submit a proposed sampling, logging, and coring program to the OGC's Victoria office. This proposed program will be reviewed and revised, as necessary, to ensure that a legacy of adequate data exists for the project. While operators can request modifications or waivers of logs and/or cores on a well-by-well basis, this

[4] See Attachment 1 for more detail on these requirements.

approach is more cumbersome and is not recommended. In any case, all information collected (samples, cores, etc.) must be forwarded to the Commission in a timely fashion.

In the case of test holes, the OGC may attach any requirements for logs, tests, or analyses as conditions of the authorization (section 18.7). The results of any such testing must be forwarded to the Commission within 30 days.

Flow Testing and Flaring

Flaring is frequently required during the initial flow testing of natural gas wells (see Gas Well Tests under Production), and during completion stages or workovers. The OGC regulates flaring under section 71(4) of the D&P Regulation. Flaring is limited in its duration and extent to allow for adequate testing while ensuring conservation of the resource and the minimization of air emissions.

For CBM wells, a longer up-front flaring period may be necessary because of the initial dewatering process and low early volumes of gas. It may take several months to a year for production tests to demonstrate representative gas rates. Further, additional flaring may be required during the production phase, for example, if compressors (see Gathering System and Pipelines) go down.

The Commission will consider allowing longer than normal flaring of CBM wells for initial flow testing, subject to a maximum volume of flared gas per well. The maximum flaring period and volume will be specified in the approval for a CBM experimental scheme or Well Authorization. As with conventional gas production, flaring during compressor downtime and other planned or unforeseen events must be kept to a minimum.

Approvals

With multiple wells in a CBM scheme, projects are likely to involve a substantial number of workovers and completions, for example, fracturing, perforating, or cavitation. Key approvals that may be required during the drilling phase include:

- An Application to Alter a Well is submitted before the well's production characteristics are changed, such as an initial completion or workover.
- An Application for Flaring Approval is submitted 5 days before any flow test or other flaring operations.
- OGC approval must be obtained for a cavitation program, including the proposed procedure for coal fines containment.

The Commission is currently preparing an information letter that will require notification, rather than application, for the initial completion of any oil, natural gas, or CBM well. Similarly, flaring upon initial completion of a well will be on a notification basis, subject to volume limits that have yet to be determined.

Produced Water Management

The process of de-pressuring the coal seam can generate large volumes of water of varying quality from fresh to highly saline. Subsurface water is regulated under the D&P Regulation, which requires that water produced from natural gas operations, including CBM, be disposed of in an underground formation, unless otherwise permitted (section 94.4). Water discharged to the surface is viewed dealt with under the provincial *Waste Management Act* on a case-by-case basis.

Surface Disposal

At the present time, an operator must apply for a permit (section 10) or approval (section 11) under the *Waste Management Act* to enable the surface disposal of water produced from a gas well. The application is made to the OGC and forwarded to the Ministry of Water, Land and Air Protection (MWLAP) for review and comment. MWLAP, as the province's environmental authority, ensures that the proposed water disposal conforms to provincial requirements and provides recommendations to the Commission regarding the disposal application. The OGC may then issue a permit or approval, usually with conditions based on MWLAP recommendations.

Currently, to determine whether a type of surface disposal is appropriate, CBM produced water must be rigorously tested for total dissolved solids (e.g., salts) and other pollutants (based on *Draft Standards for the Discharge of Produced Water from Coal Bed Methane Operations – Draft: July 8, 2002 Version*). Only water that is screened against the Standards document and has been authorized by a permit may be discharged.

In order to facilitate the processing of a CBM produced water surface disposal application, an operator should consult the above Standards document, as well as the *Procedures for Using* and *Rationale to Accompany* the standards. The Commission and the Environmental Protection Division of the appropriate MWLAP regional office should be contacted as early as possible in the project planning process for assistance in, and planning for, the interpretation of this performance-based Standard.

Subsurface Injection

An operator can apply for approval to inject subsurface water into an underground formation, where the volume or quality of produced water makes surface disposal inappropriate (e.g., the water is highly saline). In this case, the operator must submit an application to the OGC, along with a Checklist for Approval to Dispose of Produced Water. A notice will be published in the BC Gazette allowing other subsurface owners 3 weeks to express any concerns with the proposed disposal program. The Commission will then review these concerns, along with the nature of the produced water and the receiving formation, and may issue an approval with any necessary conditions attached. Ongoing water injection requires the submission of a Monthly Injection/ Disposal Statement.

Data Reporting and Confidentiality

A CBM experimental scheme allows for a longer time period of confidentiality of well data. Data from a given well on a scheme will be released 3 years after the OGC or MEM receives the well data or well report (section 57.4.e of the D&P Regulation). Similarly, test hole data is confidential for 3 years following the rig release date. For a conventional natural gas well, the confidentiality period ranges from 2 months to one year from the rig release date, depending on the well type (see Well Classification under Well Approvals).

The reporting requirements for CBM wells are essentially the same as those for conventional gas wells (see sections 49-57). For example, the Commission must be notified within 24 hours after drilling has commenced on a well (spud report), and wellbore drilling data, as contained in the Daily Reports, must be submitted. Copies of well logs must be provided within 30 days of being completed. An operator has 30 days from the rig release date to submit a Well History Report for exploration outpost or wildcat wells. Completion and Workover Reports must be provided within 30 days of the completion or workover operations. Other key drilling reports are listed under Operations Engineering Forms and Checklists (www.ogc.gov.bc.ca/formschecklists.asp).

Gathering Systems and Pipelines

The design, construction, operation, maintenance and abandonment of gas gathering systems, pipelines, and compressor facilities must meet the requirements of the *Pipeline Act* and *Pipeline Regulation*, as well as various codes and practices (e.g., CSA Z662). A paramount concern is to ensure the safety and integrity of the pipeline or facility with respect to people and the environment. Approval of the OGC is required.

Applications for other production facilities must be submitted to the OGC under section 100.1 of the D&P Regulation. In addition, under *the Land Act*, the right to occupy public land for pipelines and facilities requires an application to the Commission, subject to a review process that is essentially the same as for well applications.

Compared to a conventional gas well, a CBM project typically involves low-pressure gas gathering lines. Several stages of compression may be required to reach pipeline pressures, which may result in more compressor stations and machines. Overall, the production site may be characterized by an extensive infrastructure of gas and water lines (often laid in the same trench), compressors, pumps, electricity feed lines, and other major equipment.

The OGC may consider gathering system and pipeline variances on a case-by-case basis. The Commission will need to be satisfied that safety is ensured in all cases. Proponents are urged to enter into discussion with the Pipelines contact early on in the planning process should a variance be anticipated.

As with a conventional gas well, a CBM operator must submit an Application for a Production Facility (BC-20) and an Application for a Well or Facility to Facility Linkage (BC-21). These forms cover production measurement (metering) and accounting, material handling, equipment spacing, air emissions, spill control measures, emergency response plans, production tracking linkages, and other information. Any proposals to vary from the standard requirements for conventional gas operations should be identified in the application process. CBM proponents are advised to notify OGC staff as early as possible of their proposed infrastructure, to allow a proper assessment of the design, safety, operational, and environmental impacts.

Metering

The standard requirement for measuring production at gas wells is that each well must have its own meter unless otherwise approved by the Commission. This requirement has been relaxed for individual well measurement at some conventional wells when the applicant has provided evidence that the following conditions have been met:

- All wells involved have the same ownership.
- There is a common pool or all wells are part of an approved Unit.
- Royalty factors are equivalent for all wells.
- Group measurement with periodic well testing is undertaken to enable a reasonable allocation of product back to each well.

The same criteria will apply to an application to relax individual well metering for a CBM project. Again, any request to vary from the standard should be identified in the Facility Application, which should also include the proposed method for group measurement and allocation.

Production

CBM Zone/Formation

For any given conventional gas well, OGC geologists designate a specific pool and formation in which the well is located. A similar designation will be made for CBM wells.

Wells may be located in formations where both conventional and CBM potential exists. Section 41.1 of the D&P Regulation requires Commission approval for production from multi-zone wells. The OGC will regard production from multiple coal seams within a coal zone to be production from a common formation and will not require commingling approval. Production from CBM wells open to both coal and conventional reservoirs will be regarded as multi-zone or commingled production. Although the Engineering and Geology Branch will review each productive CBM well, proponents are expected to submit commingling applications as required. Should it be unclear as to whether a commingling application is required, the proponent is encouraged to contact the Branch (see CBM Zone/Formation contact) to discuss the situation.

Off-target Penalties and Gas Allowables

Under section 10.5 of the D&P regulation, a conventional gas well completed outside the target area is subject to an off-target penalty. If the lease has more than one normal spacing area, one gas well may be completed in each area and no penalty will be assessed, as long as the designated setback is observed (section 10.4). Where the well is off-target, an operator must apply for a daily gas allowable, as per section 88.1.

It is not feasible to limit production at CBM wells. In order to be commercially viable, a well must operate at full capacity to complete the dewatering process and reach its full gas production.

Because of these unique characteristics, the OGC will not assign any gas allowables to CBM wells. Wells in off-target areas will not be allowed to produce unless a waiver is obtained from the affected tenure holder in question.

Pressure Surveys

Reservoir pressure measurements are required on all producing natural gas pools in British Columbia, in accordance with section 95 of the D&P Regulation. All new conventional gas wells must have an initial static bottom hole pressure measurement, followed by an annual measurement of a portion of the wells in the producing pool.

In the case of CBM development wells, initial testing may yield non-representative pressures, since dewatering can take weeks or months. As a result, annual testing of all CBM wells in a given scheme is neither practical nor necessary.

For each CBM scheme, the Commission will require a representative initial pressure test, but will waive the requirement for annual testing. However, because a prudent CBM operator will want to obtain representative pressure measurements throughout production, it is recommended that periodic testing be conducted, preferably on observation or suspended wells in the scheme. The data from such testing can be useful for determining spacing and drainage needs.

Where pressure testing is conducted, all results must be reported to the OGC. Test reports, accompanied by the Reservoir Pressure Survey Test Report, must be submitted to the Commission's Victoria office within 60 days of completion of the test.

Gas Well Tests, Injectivity Testing, and Gas Well Stream Analysis

Every conventional gas well is required to be flow tested and its absolute open flow (AOF) potential determined before the well has been producing for six months, as per section 84 of the

D&P Regulation. For a CBM well, however, peak levels of gas production may not occur until many months after the start of production, so that AOF testing is not meaningful. Therefore, the Commission will waive the requirement for gas well tests of CBM wells under the authority given by section 84(2).

Water injectivity and fall-off pressure tests can help determine the permeability of a CBM reservoir. This information, in turn, is useful in estimating the flow rates and ultimate gas recovery from the reservoir. Data on seam pressure and permeability are typically only needed for CBM exploration or delineation wells, to indicate the viability of a field. They are neither practical nor necessary for development wells. While the Commission does not require injectivity testing for CBM wells, the results of any tests that are performed must be submitted to the Commission's Victoria office within 60 days, with an attached Reservoir Pressure Survey Test Report.

Section 90 of the D&P Regulation requires that the fluids and gas produced from a natural gas well be analyzed at least once a year during the first 2 years of production and at other times requested by the Commission. The results, including the proportions of liquids and gas produced and a representative gas composition analysis, must be submitted to the Commission within 60 days of the testing.

Initially during production, a CBM well may produce mostly water and a mixture of gases (methane, carbon dioxide, nitrogen, and others). Since coal preferentially desorbs methane to carbon dioxide, gas composition will vary over the life of the well. To get a representative gas analysis may take considerable time in the case of CBM. It is appreciated that an operator will be motivated to obtain reliable gas analysis results and that data must be not only timely but of good quality. Consequently, the Commission will be flexible on the timing requirement for gas well stream analysis at CBM wells.

Data Reporting

For any CBM experimental scheme, the operator will be required to submit a report every 6 months in the first year, and then annually thereafter, on the progress, performance, and efficiency of the scheme. The progress report will contain the following:

- The daily average rate of gas and water production during each month for each producing well, and for the scheme as a whole;
- The monthly cumulative gas and water production for each producing well, and for the scheme as whole;
- A representative sample analysis of produced water obtained once every 6 months;
- The date and type of any well treatment or workover for any well in the scheme;
- All information gathered to evaluate the CBM reservoir qualities such as gas content, desorption analysis, injectivity tests, and permeabilities of coal seams; and
- Any other information that is considered necessary, in the opinion of the Commission, to evaluate the progress, performance, and efficiency of the scheme.

These reporting requirements will be specified in the approval for the experimental scheme.

Royalties

On March 1, 2002, British Columbia introduced a new royalty for CBM containing the following provisions:

- Produced water handling costs are now included in the producer cost of service allowance, to cover the added water management costs;

- A royalty bank has been created to collect excess allowance for use against future assessed royalties;
- The low productivity royalty rate adjustment factor threshold is increased to 600,000 cubic feet per day from 180,000 cubic feet per day, to address the lower production rates; and
- A $50,000 royalty credit will be provided for CBM wells drilled by February 29, 2004.

Abandonment and Restoration

Plugging and Abandonment

Any well or test hole must not be left unplugged or uncased after it has served the purpose for which it was drilled (section 44.1 of the D&P Regulation). In the case of wells, cement is generally required to isolate the formation and prevent the flow of gas and water. Cement plugs, cutting and sealing of the well casing, and other requirements are specified in section 45.3 of the D&P Regulation. Prior to abandonment, an operator must submit an Application to Abandon a Well for Commission approval of the abandonment program. Sufficient information (e.g., logs) may be required to enable evaluation of the program's effectiveness.

Likewise, plugging programs for the abandonment of test holes require Commission approval, and some supporting information may be required.

Surface Restoration

Before abandoning a well, test hole, or production facility, the operator must remove all equipment and waste materials, restore the land as closely as is reasonable to its original condition, and apply to the Commission for a Certificate of Restoration (section 48 of the D&P Regulation). The application must be accompanied by a *Waste Management Act* Site Profile, which is used to determine if a location may be contaminated. Where there is potential for contamination, further investigation of the site will be ordered and, if confirmed, any contamination must be remediated to the appropriate standards.

The Commission may issue the Certificate of Restoration when it is satisfied that the restoration is complete, or when the operator files a signed release from the landowner. For developments in the Agricultural Land Reserve, the Land Reserve Commission must confirm the restoration before a certificate can be issued.

Attachment 1: Contacts

Subject Area	Contact/Office	Phone
General CBM policy	Derek Brown, MEM (Victoria)	250-952-0432
Geophysical Exploration	Kelly Harrison (Fort St. John)	250-261-5720
Petroleum and natural gas rights	Petroleum Lands Branch, MEM (Victoria)	250-952-0335
Experimental schemes	Peter Attariwala (Victoria)	250-952-0311
Well authorizations	Devin Scheck (Fort St. John)	250-261-5720
Test holes	Devin Scheck (Fort St. John)	250-261-5720
Well spacing/site size	Bruce Cazes (Fort St. John) Don Buckland (Fort St. John)	250-261-5759 250-261-5761
Surface casing/BOP	Don Buckland (Fort St. John) Bruce Cazes (Fort St. John)	250-261-5761 250-261-5759
Equipment spacing/rig standards	Bruce Cazes (Fort St. John)	250-261-5759
Worker safety	Bud Phillips, WCB (Fort St. John)	250-785-1283
Samples/logs/cores	Jeff Johnston (Victoria)	250-952-0355
Flow testing/gas well tests	Ron Stefik (Victoria)	250-952-0310
Flaring	Richard Slocomb (Fort St. John)	250-261-5763
Data reporting and confidentiality	Peter Attariwala (Victoria)	250-952-0311
Gathering systems	George Holland (Fort St. John)	250-261-5760
Pipelines	Richard Caesar (Fort St. John)	250-261-5790
CBM zone/formation	Jeff Johnston (Victoria)	250-952-0355
Off-target penalties/gas allowables	Peter Attariwala (Victoria)	250-952-0311
Water disposal	Craig Gibson (Victoria)	250-952-0294
Pressure surveys/injectivity testing/ gas well stream analysis	Ron Stefik (Victoria)	250-952-0310
Royalties	David Molinski, MEM (Victoria)	250-952-0518
Abandonment and reclamation	Dave Krezanoski (Fort St. John)	250-261-5762

Attachment 2: Surface Casing, BOP, and Equipment Spacing

Consistent with the move to performance-based regulation, the OGC will apply minimum requirements to three cases for evaluation: Rank Exploratory, Initial Field Delineation, and Development of Defined Field. These requirements hold for both authorized wells and test holes. In all cases, operators are responsible for conducting the necessary research to justify their decisions and for having the supporting information available should the Commission choose to review it.

Case 1: Rank Exploratory

If there is little or no drilling information for the immediate area, then the drilling program must follow the conventional D&P Regulation, as defined above (full Class A BOP stack, etc.).

Case 2: Initial Field Delineation

When the CBM boundaries are not clearly defined and some uncertainty exists as to area geology, then the following minimum requirements apply and the operator must have supporting geological, drilling, and risk assessment information available to the Commission upon request:

Surface Casing

- Set minimum of 25 m into competent formation
- Pressure cement to the surface in the annulus
- Subsequent casings run to be cemented to surface (groundwater protection – shallow surface casing)
- Capable of holding the maximum allowable casing pressure (MACP) expected at the shoe
- Capable of supporting BOP system

Well Control Equipment Considerations (commensurate with anticipated pressures)

- Ability to close in on pipe (annular) from remote location
- A secondary method of closing in on open hole from a remote location
- Ability to hold pressure (shut in well) while retrieving core
- Ability to control well
  - Monitor hole fill trip tank and mud tank volume
  - Ability to monitor mud properties
  - Ability to degas mud if necessary
  - Manifold for choke line
  - Ability to read pressures
  - Rig personnel trained in blowout prevention and well control
- Ability to pump kill fluids
- Working spool (for kill and choke/flare lines)
- Ability to monitor for and detect gases

Wellsite Equipment Spacing

- Flare stack 50 m from wellhead
- Wellsite offices 25 m from wellhead, 40 m from flare stack
- Sleeping quarters 50 m from wellhead and flare stack

Case 3: Development of Defined Field

The requirements set out in Case 2 Initial Field Delineation may be relaxed through risk assessment in development drilling situations where representative wells have been drilled in the area, geological control is known to be representative and accurate, and the proposed wells are

clearly for CBM development only. Reference information supporting any application of this nature must be complete and available to the Commission upon request:

Surface Casing

- Must satisfy all requirements set out in Case 2, with the following exception
- May use pressure-cemented conductor set at a minimum of 15 m into competent formation

Well Control Equipment

- Must meet all requirements set out in Case 2, with the following exceptions
- May use Alberta Class 1A diverter system with the ability to remotely close in on pipe or open hole using annular
- Choke manifold not required
- Must be able to control well from surface at all times

Wellsite Equipment Spacing

- Must satisfy requirements outlined in Case 2 with the following exceptions
- Flare stack 25 m from wellhead
- Sleeping quarters 25 m from wellhead and 40 m from flare stack (wellhead gas detection with alarms in sleeping quarters are required in this situation)

In all cases, the operator is required to conform to the WCB requirements with respect to wellsite equipment spacing (*Workers Compensation Act*; *Occupation Health and Safety Regulation*, Part 23: Oil and Gas). As mentioned in the Well Spacing and Site Size section, the Commission continues to work with the WCB to development specification for reduced equipment separation distances that will be suitable for CBM projects.

For now, for any reductions from Case 1 Rank Exploratory (i.e., full adherence to the D&P Regulation), the operator must contact the WCB (see Contacts) to ensure compliance. All drilling programs should be designed and carried out by qualified and competent personnel.

RIG STANDARDS

In some cases, CBM wells may be drilled using rigs and crews that are normally engaged in water well drilling or mineral coring. The Commission requires that both the equipment and personnel employed in a rig be capable to do the work of drilling a gas-producing well. Operators must ensure that their rigs meet the following requirements:

- Equipment certified for intended work (name plated)
- Hoisting capability to meet CAODC standards
- Equipment capable of drilling with drilling fluid and/or air
- Crew trained in working with natural gas
- Operations representative at wellsite with valid 2nd Line BOP Supervisors Certificate (PITS) and Rig Manager (toolpush) and Drillers with 1st Line BOP Supervisors Certificate (PITs)
- Sufficient crew to safely perform required tasks

Gas monitoring while drilling may be required.

Attachment 3: Glossary

The following definitions relate to terminology as it is used in this document:

Abandoned – A well that is permanently closed off when it is depleted and no longer capable of producing profitably.

Abandonment – Converting a drilled well to a condition that can be left indefinitely without further attention and will not damage freshwater supplies, potential petroleum reservoirs, or the environment.

Absolute open flow (AOF) potential – Productive capacity at a gas well that is open to the atmosphere (zero backpressure).

Annular – A large doughnut-like valve used in a BOP stack that is mechanically squeezed inward to seal on the pipe.

Blowout – An uncontrolled flow of gas, oil, or other fluids from a well.

Blowout Preventor (BOP) – Equipment installed on the wellhead to prevent the escape of fluids under pressure from the wellbore during drilling, completion, or workover operations. The BOP stack incorporates different sets of hydraulic rams enabling shut in of the well with or without pipe in the hole, pumping of fluids into the well under pressure, and controlled release of fluids from the well.

Borehole – The wellbore; the hole made by drilling or boring a well.

Bottom hole pressure – The pressure in a well at a point opposite the producing formation.

CAODC – Canadian Association of Oilwell Drilling Contractors.

Casing – Steel pipe used in wells to seal the borehole from formation fluids and reinforce the walls of the borehole.

Cavitation – A mechanical method, usually with high-pressure water jets, of creating a cavity around the wellbore in a coal formation so as to increase the area of the coal exposed to the wellbore.

Coalbed methane (CBM) – The natural gas found in most coal deposits; formed during coalification, the process by which plant material is converted into coal over millions of years.

Completed well – A well that has had the necessary work done to enable production.

Completion – The process of finishing a well so that it is ready to produce gas.

Compressor – A machine used to boost natural gas pressure to move it through pipelines or other facilities.

Core – A cylindrical borehole sample for analysis of various properties of the formation, including porosity, permeability, fluid content, and geological age.

CSA – Canadian Standards Association.

Delineation well – A well that extends that boundary of a previously discovered pool.

Desorption – The process of detaching methane adsorbed onto coal by de-pressuring the coal seam through dewatering and other methods.

Development well – A well drilled in or adjacent to a proven part of a pool to optimize production.

Dewatering – The process of removing water from a coal seam in the vicinity of a producing gas well. Dewatering is required to reduce pressure within the coal seam, which in turn allows the methane gas to be released from the coal.

Directional drilling – A well drilled at an angle from the vertical. This method can be used when local topography (e.g., river banks or other water bodies) prevents vertical drilling. Under normal conditions, vertical drilling is used (i.e., the bottom of the hole is located beneath the drill rig).

Diverter – A device used to direct fluids flowing from a well away from the drilling rig.

Drill pipe – Steel pipe sections of about 9 m in length that are screwed together to form a continuous pipe extending from the drilling rig to the drilling bit at the bottom of the hole. Rotation of the drill pipe and bit causes the bit to bore through the rock.

Drill-stem test – A method of gathering data on the potential productivity of a formation before installing casing in a well. A drill stem test records pressure and fluid recovery data from which formation characteristics can be inferred.

Exploratory well – A well drilled in an unproven area where no oil or gas production exists nearby.

Formation – A designated subsurface layer that is composed throughout of substantially the same kind of rock or rock types.

Flaring – The burning of natural gas as a means of disposal. It is restricted primarily to short-term testing, well workovers, or exceedingly rare emergency situations.

Fracturing – The practice of pumping special fluids down the well under high pressure; hydraulic fracturing causes the formation to crack open, creating passages for the reservoir fluids to more easily flow into the wellbore.

Gathering system – The pipelines and other infrastructure that move raw gas from the wellhead to processing and transmission facilities.

Kill – To prevent the threatened blowout of a well or to stop a blowout in progress, usually accomplished by the pumping of heavy fluids under pressure into the wellbore to overbalance the formation pressure.

Log – A detailed depth-related record of geological, formation attribute, and hydrocarbon potential data obtained by lowering measurement instruments into a well.

Observation well – A non-producing well used to monitor pool pressure, usually included in annual pressure testing surveys.

Open hole – A wellbore in which casing has not been set.

Perforate – Make holes through the casing and cement opposite the producing formation to allow gas to flow into the well.

Permeability – The capacity of a reservoir rock to transmit fluids; how easily fluids can pass through rock.

Porosity – The volume of spaces within rock that might contain oil and gas (like the amount of water a sponge can hold); the open or void space within rock.

Producer cost of service allowance – An allowance against royalties to cover the costs of gathering and processing natural gas for sale, and the costs of conserving conservation gas.

PVC – Polyvinyl chloride.

Reservoir (pool) – A porous and permeable underground rock formation containing a natural accumulation of crude oil or natural gas that is confined by impermeable rock or water barriers, and is separate from other reservoirs.

Resistivity – The electrical resistance offered to the passage of an electrical current.

Samples – The wellbore drill cuttings obtained at definite depth intervals during drilling. These cuttings can be examined to determine the rock type, the formation being drilled, and indications of gas content.

Shoe – Steel reinforcement at the end of the casing string to protect against buckling or deformation as the casing is being lowered.

Sour gas – Natural gas containing hydrogen sulphide or other sulphur compounds.

Spool – A flanged joint placed between the blowout preventer and drilling valve, serving as a spacer.

Surface casing – The first string of casing put into a well; it is cemented into place and serves to shut out shallow water formations and as a foundation for well control.

Suspended well – A well that was previously completed, but is now no longer being produced.

Tcf – Trillion Standard Cubic Feet.

Wellbore – The hole made by the drilling bit.

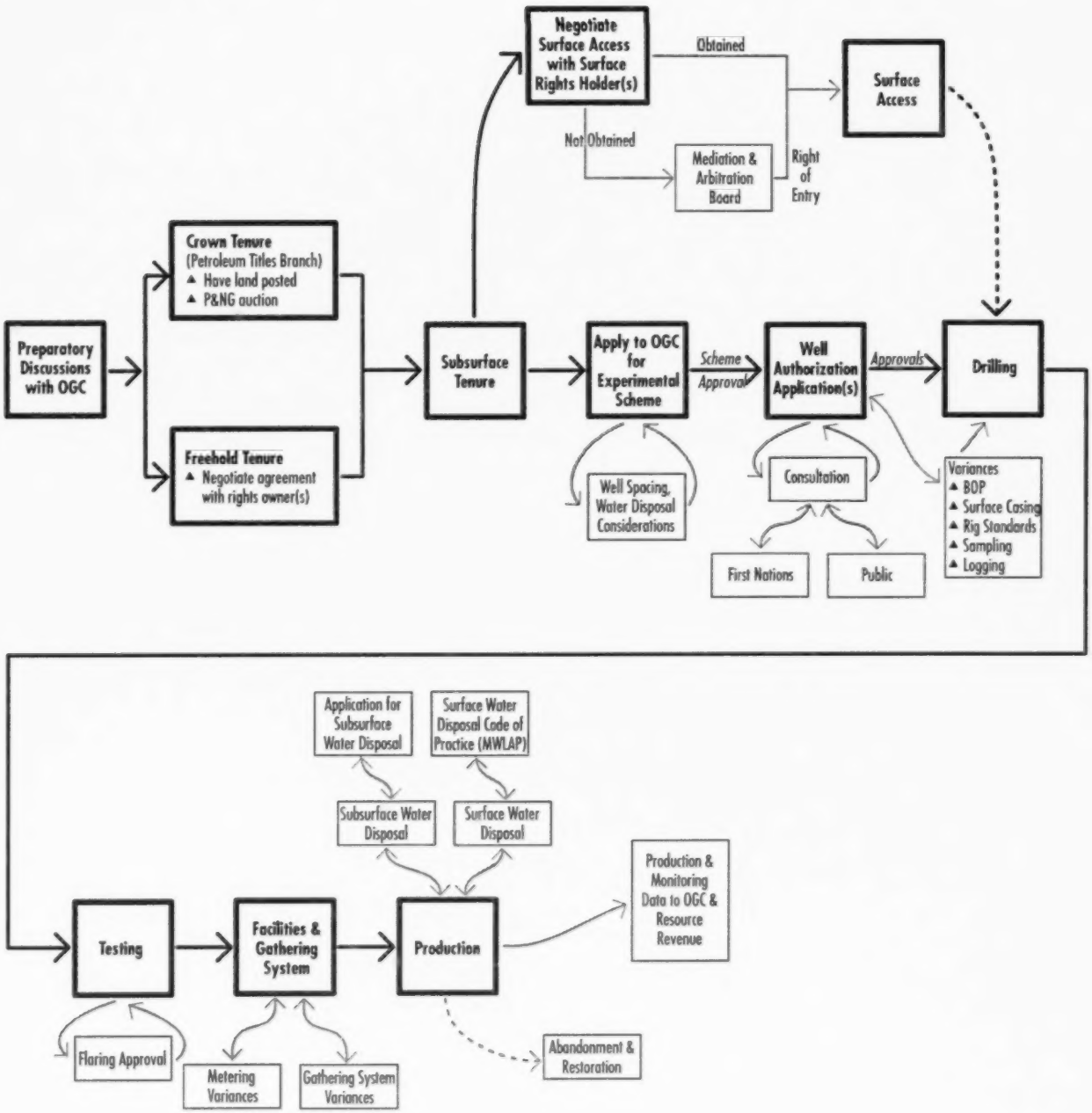
Wellhead – The equipment used to maintain surface control of a well; formed of the casing head, tubing head, and surface valves.

Well servicing – The maintenance work performed on a well to maintain or improve production levels. Examples include repairs to pumps, valves, and tubing.

Wildcat – See Exploratory Well.

Workover – Additional work required on a well to maintain or improve production. Examples include wellbore flow simulation by perforating or fracturing and installing water pumps.

Oil and Gas Commission Regulatory Process for Coalbed Methane Projects

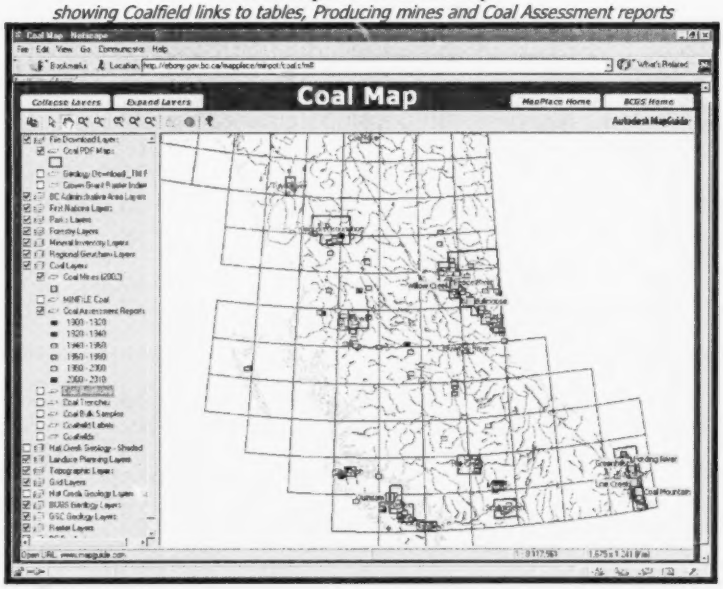


www.MapPlace.ca - A Web-based Portal for CBM Target Evaluation

- A popular Internet portal to British Columbia's comprehensive geoscience databases
- Create interactive maps with data themes such as geographic locations, topography, coal occurrences, coalfields, geology, coal tenures, coal assessment report locations, boreholes, trenches and bulk samples
- Map objects are linked to supporting database tables
- Copy and print maps
- Download data and view PDF reports
- Visit the Coal Map at the MapPlace under Selected Theme Maps

The MapPlace Coal Map

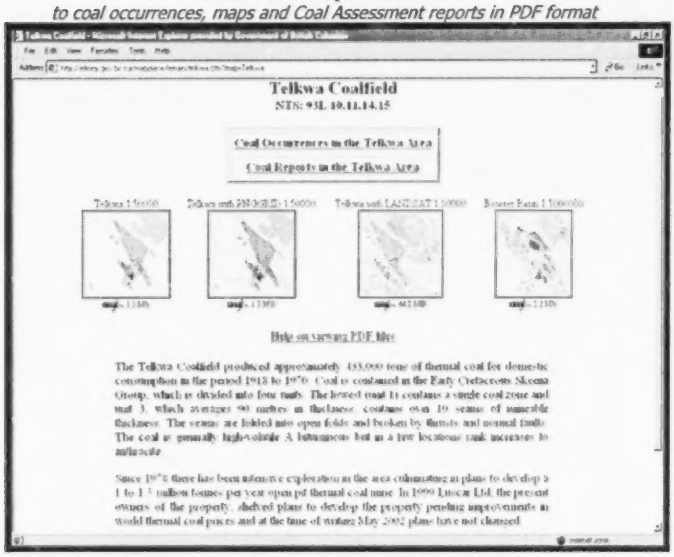
showing Coalfield links to tables, Producing mines and Coal Assessment reports



Coal Assessment Reports and Data on the Web and CD-ROM

Coalfield Reports Link

to coal occurrences, maps and Coal Assessment reports in PDF format



- A library of 827 Coal Assessment Reports submitted by exploration companies dating from 1900
- View on the Web or purchase on CD-ROM. Peace River area (198 reports on 20 CDs for $3960.00) and Crowsnest area (85 reports on 10 CDs for $1700.00). Hat Creek, Telkwa and Comox areas will be available soon.
- Exploration data from the reports, such as trench, borehole and bulk sample information, are summarized into digital tables called COALFILE
- To access the Coal Assessment Reports and COALFILE tables on the Web, visit the Coal Page or the MapPlace Coal Map

For more information on Coal Assessment Reports, COALFILE or the MapPlace visit our website or contact:

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Websites: MapPlace - http://www.MapPlace.ca or Coal Page - http://www.em.gov.bc.ca/Mining/Geolsurv/EconomicGeology/coal/

OIL AND GAS COMMISSION

Public Involvement Guideline

A guideline to involve the public in oil and gas operational planning

PUBLIC INVOLVEMENT GUIDELINES

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OIL AND GAS COMMISSION

The Public Involvement Guideline

July 2002

INTRODUCTION

The Oil and Gas Commission is committed to being transparent and accessible regulators. A series of guidelines are developed to assist our clients and the public.

This is a guideline for industry to involve the public in oil and gas operational planning. The goal of public involvement is to provide an opportunity for public input and education about oil and gas development that could affect them.

There are three sections to this guideline:

1. Developing a Public Involvement strategy
    a. Guideline purpose
    b. Roles and responsibilities of the company, the regulator and the public
    c. Who should be identified in a public involvement process
    d. Recommended strategies to complete a public involvement process
    e. The steps to complete the public involvement process
2. Recommended Minimum Distances:
    a. Minimum distance requirements for oil and gas activities
        i. Wells, Pipelines, Facilities and Geophysical
    b. Public involvement and emergency response planning
    c. Recommended minimum distances
    d. Minimum information requirements for consultation radius
3. Submitting a Record of Public Involvement:
    a. Reporting the public involvement process to the OGC
    b. Submitting an application and the public involvement process
    c. Steps to take by the public if they have concerns

BACKGROUND

Role of Government in Resource Development

The Government of British Columbia promotes the sound, safe and efficient development, the conservation and equitable management of provincial oil and gas resources, fostering a healthy environment, a sound economy and social well being for British Columbians.

Role of Regulator

The Oil and Gas Commission regulates oil and gas activities and pipelines in the province, to ensure oil and gas activities are authorized and operate with regard for environmental, economic and social effects.

Relationship between public involvement and Land and Resource Management Planning

94% of British Columbia's natural resources are publicly owned. The Government of British Columbia uses strategic land use planning to determine how provincial land will be used. This planning mechanism is called the Land and Resource Management Plans (LRMPs).

LRMPs are integrated resource plans for the use and management of public provincial lands and resources. As a government agency, the Oil and Gas Commission implements the LRMPs when conducting environmental reviews of oil and gas projects. LRMPs also give useful information to the public and oil and gas companies on what is expected when conducting a public involvement process. The plan states: [the public and oil and gas companies must take] ***into consideration other resource values, rights, tenures and development opportunities, recognizing the biological and physical limitations of the land and resources.***

How Government uses information gathered from public involvement

The Commission encourages companies to involve the public when planning oil and gas projects. The purposes of public involvement are:

- to identify parties who may be impacted by, or have an interest in the project;
- to identify concerns or issues that might arise from the project;
- to create an opportunity to develop company commitments in response to local input;
- to improve the use of local experts and traditional environmental knowledge;
- to focus on and resolve real public concerns and issues, rather than regulatory procedures and administration;
- to provide appropriate information to the Oil and Gas Commission to enable a fair and balanced decision; and,
- to expedite decision-making.

There are four stages to an involvement process:

Four stages of a public involvement process	
Stage one Information Dissemination	Information dissemination means to distribute information about the oil and gas project. There is no engagement and is strictly a notification tool. Information dissemination may be an appropriate involvement vehicle in some circumstances, for example, notifying about ongoing activities.
Stage two Consultation	Consultation is a two-way exchange of information between companies and the parties impacted by the oil and gas project. This method is frequently used by companies for learning about any issues or concerns the public may have with a project.
Stage three Participation	Participation includes dialogue about how the company and impacted parties will interact to plan a project. Ground rules and simple agreements are made between the company and interested parties specifying issues, which will require joint planning and necessitate

	input from the public. The Oil and Gas Commission encourages proponents to use stage three of the involvement process, where possible.
Stage four Negotiation	Negotiation means to establish agreements and to identify and accommodate mutual interests derived from the project. Negotiation is a voluntary process, and the company and the public participate as co-equals. **Negotiation is a meaningful method to build relations.** When there are concerns and opportunities for both parties arising from oil and gas activities, this may be an appropriate involvement vehicle.

SECTION I
DEVELOPING A PUBLIC INVOLVEMENT STRATEGY

Guideline purpose

This guideline is a resource tool for companies to develop public involvement process.

All companies who submit applications to the Oil and Gas Commission (Commission) are encouraged to involve the public in oil and gas operational planning. A public involvement process allows stakeholders and First Nations to participate in planning with the proponent about oil and gas operations affecting them.

This guideline recommends how oil and gas companies, First Nations and stakeholders can establish a forum for ongoing discussions and understanding.

Users of the guideline

The Oil and Gas Commission encourages applicants to use the guide. We also recommend First Nations and stakeholders reference the guideline when undertaking an involvement process.

Roles and responsibilities of the oil and gas company, the regulator and the public in a public involvement process

Applicant	Public (landowner, occupant, affected parties)	Oil and Gas Commission
1. Conduct a public involvement process with landowners, occupants and affected parties to identify concerns or issues. 2. When appropriate, modify activity plans to mitigate	1. Provide summary of issues or concerns to the proponent and the Oil and Gas Commission. Affected parties are encouraged to document concerns through a letter or through the	1. Determine if satisfactory and representative level of landowner, occupant and affected resident input was used in the activity planning. 2. Assess issues, and evaluate if appropriate measures were

public concerns. 3. Keep all documentation to demonstrate completion of public involvement process.	"Unresolved Concern Form". 2. Provide summary of recommended mitigation commitments.	taken to address concerns. 3. Recommend the use of Appropriate Dispute Resolution (ADR) when appropriate.

Recommended strategies to complete a public involvement process

The method used to complete a public involvement process will vary by the project. Some things to consider when designing the activities in a company's public involvement process:

a) the complexity of project related to project size and time span
b) the proximity to community
c) historical relationship between the company and the community
d) health and safety issues associated with the activity
e) other resource users or tenure held in the area
f) the environmental setting of the project

Each oil and gas project and the impacted public are unique; tools should be selected to fit the circumstances.

Some commonly used vehicles to build relationships between a company and the public include:

- Organizing meetings with community representatives and conducting open houses;
- Attending community functions;
- Making personal home visits and following-up with telephone conversations;
- Sending regular and **timely** mail, newsletters and e-mail updating on project status;
- Placing advertisements in local newspapers and public buildings; and,
- Hiring a local company representative.

Completing the public involvement process

A public involvement process is complete when the oil and gas company has:

- consulted and notified all affected parties, and/or those identified in the recommended Minimum Distance table. See section II.
- documented concerns and actions to mitigate concerns

In addition, affected parties are encouraged to participate in the process by:

- documenting concerns, and
- meeting with the oil and gas company to offer solutions and recommendations

SECTION II
RECOMMENDED MINIMUM DISTANCES

A guideline to involve the public in oil and gas operational planning – Recommended minimum distance requirements

The following table on pages 6-8, indicate the minimum distances from the activity within which

- the proponent should involve the public through consultation/notification about the development and operational aspects of the project,
- inform people about the Emergency Response Plan, and/or
- notify the affected public about project sequencing.

This document is for guidance, so local circumstances may indicate that greater distances would be appropriate. The Commission may determine that a greater distance is warranted and would direct the proponent to modify the extent of consultation/notification.

Public involvement and emergency response planning

Proponents are required to inform persons in the Emergency Response Plan Zone (EPZ) about the Emergency Response Plan (ERP), prior to the final assembly of the ERP.

Emergency Response Planning requirements for sour wells:
Emergency Response Plans for special sour wells must be approved before a program application is authorized. The Oil and Gas Commission requires a *site-specific plan* when there are any residences within the emergency planning zone. This Plan must be approved and in place prior to commencing drilling. Where there are no permanent residences within the minimum 100 meters and the potential release rate is less than 0.01 m^3/sec. there may be no need for an Emergency Response Plan.

Pipeline and facilities:
As outlined in the *Pipeline Act, Sour Pipeline Regulation*, Emergency Response Plans must be approved before commencement of pipeline and facility operations. See the *Pipeline Act* for specification of Emergency Response Plan requirements.

Wells[1]

Application	Personal Consultation	Emergency Response Plan Consultation	Notification
Sour Well Authorization	• landowner • occupant • all residents living within .5 kilometre	• all residents living within the Emergency Planning Zone (EPZ)	• local government authorities whose boundaries are within 3.0 kilometres of EPZ.

[1] See definitions for description of "local government authorities" and "First Nation".

Sweet Well Authorization	• Landowner • Occupant • all residents living within .5 kilometre		• local government authorities whose boundaries are within 1.5 kilometres of the well site.
Well test flaring			• all rural residents and administrators of any incorporated centres within at least 3.0 kilometre radius.
Single oil well – continuous flare Sweet or sour	• landowner • occupant • all residents within .5 kilometres		

Pipelines

Application	Personal Consultation	Emergency Response Plan Consultation	Notification
Sour Pipeline – (contain concentrations greater than 1 mole % H_2S)	• Landowner • Occupant	• all residents living within the Emergency Planning Zone	• local government authorities whose boundaries contain or are within 1.5 kilometres of the EPZ • local government authorities
Hydrocarbon Pipelines less than 406.4 mm (16NPS)	• Landowner • occupant	• all residents living within the Emergency Planning Zone	• local government authorities whose boundaries contain or are within 1.5 kilometres of the project
High Vapor Pressure Pipeline	• Landowner • Occupant	• all residents living within the Emergency Planning Zone	• local government authorities whose boundaries contain or are within 1.5 kilometres of the project
Sweet Pipeline	• Landowner • Occupant		• local government authorities whose boundaries are within 0.5 km

Facilities

Application	Personal Consultation	Emergency Response Plan Consultation	Notification
Sour Facility	• Landowner • Occupant • all residents living within 1.5 kilometres	• all residents living within the Emergency Planning Zone	• all residents living within 3 kilometres • local government authorities whose boundaries are within 8.0 kilometres of the EPZ • local government authorities

Compressors and pumps	• Landowner • occupant		• interested persons
Sweet Facility	• landowner • occupant • all residents living within 0.5 kilometres		• local government authorities whose boundaries are in or within 1.5 kilometres of the project.

Geophysical

Application	Personal Consultation	Emergency Response Plan Consultation	Notification
Geophysical	• Landowner • Occupant • Trappers		• all residents living within 0.4 kilometres of each side of the line location • local government authorities whose boundaries are within 1 km

Minimum information recommendations for public involvement

Minimum recommended information requirements for consultation radius:

Information required to enable a member of the public to understand the implications of a proposed activity on his or her rights and interests which may include:

- Company name, company contact person, phone number, facility location and type;
- A brief description of the proposed activity and how the activity relates to, or is part of the existing development in the area;
- Project scheduling and the proposed date of the activity initiation and construction;
- A brief description of the equipment to be installed;
- A description of any flaring that might occur;
- Possible sources of odors and proposed measures to control or eliminate them;
- Scope of emission and control measures;
- Noise emissions associated with the activity and planned mitigative measures;
- Amount, type and timing of vehicle traffic that might be associated with the activity;
- For sour wells, production facilities and pipelines, a discussion and supporting information which will allow a member of the public to understand the potential implications of an uncontrolled release of H_2S and the contingency plans to safeguard the public; establishes the H_2S content for each sour zone which may be encountered;
- A discussion about the potential for sour zones;
- Calculation of the combined maximum potential H_2S release rates having regard for the drilling program and design of the well; and,
- A map which locates the proposed activity in relationship to dwellings, public facilities and urban centres.

Minimum recommended information requirements for notification radius:

Information required to enable a member of the public to understand the implications of a proposed activity on his or her rights and interests which may include:

- Company name, company contact person, phone number, facility location and type;
- A brief description of the proposed activity and how the activity relates to, or is part of the existing development in the area;
- Project scheduling and the proposed date of the activity initiation and construction;

- Possible sources of odors and proposed measures to control or eliminate them;
- Scope of emission and control measures;
- Noise emissions associated with the activity and planned mitigative measures;
- Amount, type and timing of vehicle traffic that might be associated with the activity; and
- A map which locates the proposed activity in relationship to dwellings, public facilities and urban centres.

Minimum recommended information requirements for emergency response plan information process:

- Company name, location of the activity;
- Explanation of the potential hazard of an uncontrolled release of H_2S and SO_2 should the gas ignite;
- Characteristics, dangers and origins of H_2S and SO_2.
- Explanation of evacuation procedures;
- Explanation of ignition procedures;
- Explanation of evacuation of schools, hospitals and homes of the aged;
- Location of evacuation centers;
- Sample of evacuation notification;
- Name of company contact and telephone number;
- Description of company response to an emergency; and,
- What precautions are taken to absolutely minimize the chance of an emergency.

SECTION III
SUBMITTING RECORD OF PUBLIC INVOLVEMENT

Reporting the public involvement process to the Oil and Gas Commission

Applicants are encouraged to document their public involvement processes.

In situations where there are unresolved concerns between the company and impacted public, applicants are to submit to the Oil and Gas Commission the "*Public Involvement Report*" form. Also submit documentation of the involvement process. The Oil and Gas Commission will use this information:

a) to evaluate the situation

b) to consider the appropriateness of further facilitation, and

c) to make a decision

PUBLIC INVOLVEMENT DOCUMENTATION REQUIREMENTS

The Oil and Gas Commission recommends oil and gas companies keep the following information, detailing their completed public involvement process. The regulator may request at any time to review the information.

Documentation of the stakeholder involvement process should include the following:

- A description of the stakeholder involvement process completed;
- A line list of persons notified;
- A line list of persons consulted;
- A copy of all notification information;
- A description of any outstanding issues;
- A description of mutually acceptable agreements made; and,
- A map showing the location of proposed activity and the persons within both the consultation and notification distances.

See page 15 for the "Public Involvement Report" form.

Submitting an application and the public involvement process

Companies are encouraged to complete their public involvement process prior to making application. This will result in better planning and improved relationships with First Nations and stakeholders.

If a dispute occurs between the applicant and an affected party, the proponent may continue with the application submission. The Oil and Gas Commission will attempt to facilitate and encourage the use of voluntary Appropriate Dispute Resolution, or may proceed with a decision based on the available information provided by all parties. The public involvement process must be completed prior to completion of the Oil and Gas Commission application review.

Steps to take by the public if they have concerns

If the public has an unresolved concern regarding a proposed project, the following steps should be followed:

- The applicant should be notified and details of the concern provided, as well as any recommendations for mitigation. The Oil and Gas Commission encourages companies and the public to attempt to resolve concerns between the two parties, prior to coming to the regulator.

- The public are also encouraged to complete the Oil and Gas Commission's *"Notice of Unresolved Concern"* form available at the Commission and on the OGC's website. This form should be sent to the proponent, as noted above, with a copy forwarded to the Oil and Gas Commission. This document will provide a formal record, and be considered part of the Commission's decision-making process. Space is provided on the form for indicating how the proposed project may affect the interested party. See page 15 for the "Notice of Unresolved Concern" form.

- Under section 8 of the *Oil and Gas Commission Act*, Appropriate Dispute Resolution (see definitions in the Guideline), is available to assist parties to resolve disputes. ADR is a voluntary process, and thus both parties must elect to participate for it to proceed.

Under section 9 of the *Oil and Gas Commission Act*, parties can apply to the Oil and Gas Commission Advisory Committee for a "Request for Reconsideration". If the First Nation, stakeholder or proponent believes the Oil and Gas Commission did not consider a concern in the decision-making process, a "Request for Reconsideration" can be made for use of appropriate dispute resolution. The party seeking the reconsideration must demonstrate new information not previously considered in the case file. "Application for Reconsideration by Consensual Appropriate Dispute Resolution" is available at the Commission, on the OGC's website, as well as at the end of this document. See page 16 for the "Application for Reconsideration by Consensual Appropriate Dispute Resolution" form.

GUIDELINE DEFINITIONS:

"emergency planning zone" means:

That area around a well, production facility or pipeline which could be exposed to hazardous concentrations of hydrogen sulphide, if a release of gas occurs from the well, production facility or pipeline, as determined in accordance with the *Drilling and Production Regulation* or the *Sour Pipeline Regulation*, as may be appropriate.

"Emergency Response Plan" means:

An outline of emergency procedures designed to ensure public safety which will be followed by the operator in the event of an uncontrolled release of oil or gas, as specified in section 58 of the *Drilling and Production Regulation.*

"First Nation" means:

In Canada, a community of aboriginal people who are represented by chief and council under the *Indian Act.*

"land owner" means:

(a) the government for land so owned,

(b) a person registered in the land title office as the registered owner of the land surface or as its purchaser under an agreement for sale, and

(c) a person to whom a disposition of Crown land has been issued under the Land Act, and, in relation to a well, includes a person entitled to produce and dispose of petroleum or natural gas from the well; *(from s. 1 of the Petroleum and Natural Gas Act).*

"local government" means:

(a) the council of a municipality, and

(b) the board of a regional district; *(from s. 5 of the Municipal Act).*

(c) Additionally, for the purpose of this guideline, the First Nations communities affected by the oil and gas activity are considered local government authorities.

"Mediation and Arbitration board" means:

When a company holds the rights to petroleum resources and needs to enter private land to access those resources, they are required to consult with the landowner. The company must also negotiate its terms of compensation for the use of the private land. If an agreement is reached, the parties sign a standard surface lease form and land title act documents, allowing the company to register the lease. However, the landowner may refuse any offer of compensation, or disagree with the proposed location or access route. Either party may apply to the Board for assistance in resolving the dispute.

"notification" means:

The supply of appropriate written information to the public about a proposed activity. Notification may lead to consultation, if a member of the public identifies, an interest that might be affected by the activity. Notification can be delivered or mailed. If mailed, the Oil and Gas Commission recommends a period of 5 working days, prior to application submission.

The person notified is responsible to contact the proponent with any concerns. Additionally, the person notified can advise the Oil and Gas Commission of concerns with the project.

"occupant" means a person, other than the owner:

(a) in actual possession of the land surface,

(b) shown on the indefeasible or absolute title to the land surface as having an interest in the land,

(c) to whom the board has granted use of or a right of entry to or the right to take the land surface; *(from s. 1 of the Petroleum and Natural Gas Act).*

"Oil and Gas Commission Appropriate Dispute Resolution mechanism" means:

Under Section 8 of the *Oil and Gas Commission Act*, the Commission, upon its own initiative or upon the request of an interested person, may authorize the use of the Appropriate Dispute Resolution process.

The Commission's ADR mechanism can be used on strictly consensual nature. ADR does not apply to issues of financial compensation, such as those within the jurisdiction of the Mediation and Arbitration Board.

"personal consultation" means:

Two-way communication that involves exchanges of information between companies and the affected public. Personal consultation involves dialogue about how the company and community will interact (process related) and provides an opportunity to address issues of mutual interest (project related).

"resident" means:

Any persons living within the distances outlined in minimum required distance table, Guideline for stakeholder involvement.

The role of the "*Environmental Assessment Act*" and its relationship with the Oil and Gas Commission stakeholder involvement process:

The Environmental Assessment Act allows British Columbians to provide input as part of the decision-making process for proposals for major projects and developments. It is the responsibility of all proponents to be aware if their project meets the criteria of the "reviewable" projects regulation of the Act. Energy projects subject to review include:

- Power generation plants
- Electric transmission lines
- Energy storage facilities
- Energy use facilities (which use, convert or process an energy source such as ethanol, methanol, hydrogen or methyl tertiary butyl ether [MTBE])
- Oil and gas transmission pipelines in accordance with one of the following dimensions:

Diameter	**Length**
≤ 114.3 mm (4")	60 km or more
> 114.3 (4") and ≤ 323.9 mm (12")	50 km or more
> 323.9 mm (12")	40 km or more

- Offshore oil and gas development (exploration and production)

"*Unresolved concerns*" means:

that through the stakeholder involvement process, the proponent has identified unresolved concerns regarding the project or the Emergency Response Plan. Proponents are required to submit copies of all stakeholder involvement process documentation for review, prior to receipt of the decision.

OIL AND GAS COMMISSION

200, 10003 - 110th Ave
Fort St. John BC V1J 6M7
www.ogc.gov.bc.ca

Phone: (250) 261-5700
Fax: (250) 261-5773
24-hr: (250) 261-5744

PUBLIC INVOLVEMENT REPORT

WA or Geophysical No.:_____ OGC File No.:_____

Name/Location:_____ Project:_____

This report must be submitted to the Project Assessment Branch of the Oil and Gas Commission together with supporting documentation, if an unresolved concern is identified. Documentation is not required to be submitted after completion of the stakeholder involvement process if there are no unresolved concerns. Documents can be requested at any time.

If a dispute occurs between the applicant and a member of the public that cannot be resolved by the parties, an application may be submitted, and the Oil and Gas Commission may encourage a consensual alternative dispute process to be undertaken.

Documentation of the stakeholder involvement process should include the following:

- Description of stakeholder involvement process completed
- Line list of persons notified
- Line list of persons consulted
- Map showing location of activity and the persons within consultation and notification distances
- Copy of all notification information
- Record of all communications
- Description of mitigative measures proposed

Details of any unresolved issues or concerns: *(attach additional sheets, if required)*

Guideline questions when preparing stakeholder involvement report:

1. Are the stakeholder involvement report minimum requirements met? Has the company carried out the minimum requirements regarding consultation/notification?
2. Is the unresolved concern being raised by someone who was within the personal consultation zone?
3. Is the unresolved concern a new item not addressed in previous consultation with the company?
4. Has the company addressed the concern in any way? How?
5. What is the potential impact of the project to the party raising the unresolved concern and to the company?
6. Is the view related to the long-term or short-term impacts of the project? Is the view related to the current application or potential future associated applications?
7. What are the timelines with respect to the application submission and planned work?

Name:		Title:	
Signature:		Company:	
Address:			
Date:	Phone:	Fax:	Email:

The personal information requested on this form is collected under the authority of and used for the purpose of administering the Oil and Gas Commision Act. Under certain circumstances, some information may be released subject to the provisions of the Freedom of Information and Protection of Privacy Act. If you have any questions about the collection, use or disclosure of this information, contact the Corporate Services Branch, Records Administrator, in Fort St. John at the address above.

OIL AND GAS COMMISSION

Stakeholder Relations and
Communications Branch
200, 10003 - 110th Ave
Fort St. John BC V1J 6M7

Phone: (250) 261-5700
Fax: (250) 261-5750
24-hr: (250) 261-5700
www.ogc.gov.bc.ca

NOTICE OF UNRESOLVED CONCERN

The OGC encourages parties to resolve disputes between themselves whenever possible.

Pursuant to the Oil and Gas Commission Guideline for Stakeholder Involvement, ***this notice is to be submitted to the Proponent/Company, with a copy to be sent to the Oil and Gas Commission.***

For Commission Use Only

Area of Interest *(please check one)*:

- ☐ Proponent
- ☐ Landowner
- ☐ Occupant
- ☐ Company
- ☐ Affected resident
- ☐ Other person having a material interest

I/We wish to notify the Oil and Gas Commission of an unresolved concern with the following party:

Name _____

Address _____

_____

_____

Phone: _____

Project description: _____

Project location: _____

OGC File number, if available: _____

Land Agent/ Company Representative: Name: _____

Phone No.: _____

Please outline the following *(attach additional sheets or documents if required)*:

1. Summary of unresolved concern:

_____

_____

_____

_____

_____

2. Summary of Public Communication Process *(meetings, phone calls, etc.)*:

_____

_____

_____

_____

_____

Applicant Name:		Title:	
Applicant Signature:		Company:	
Address:			
Date:	Phone:	Fax:	Email:

The personal information requested on this form is collected under the authority of and used for the purpose of administering the Petroleum and Natural Gas Act. Under certain circumstances, some information may be released subject to the provisions of the Freedom of Information and Protection of Privacy Act. If you have any questions about the collection, use or disclosure of this information, contact the Corporate Services Branch, Records Administrator, in Fort St. John at the address above.

OGC OIL AND GAS COMMISSION

200, 10003 - 110th Ave
Fort St. John BC V1J 6M7
www.ogc.gov.bc.ca

Phone: (250) 261-5700
Fax: (250) 261-5773
24-hr: (250) 261-5744

APPLICATION FOR RECONSIDERATION BY CONSENSUAL APPROPRIATE DISPUTE RESOLUTION

Application submitted under the authority of the Oil and Gas Commission Act, section 9 (1)… "An application to the advisory committee must be made in writing and delivered within 15 business days after the date of the original decision to (a) the advisory committee in care of the secretary, and (b) each original applicant."

For Commission Use Only	**Date Received:**

1. Name of Applicant: (please print)

2. Name of Applicant: (please print)

Name(s) of project proponent(s) or original applicant(s): **(please print)**	Type of project *(e.g., pipeline, well)*: _____ Project location: _____ OGC File number, if available: _____ Date of original decision: _____
_____ _____	

I/We hereby apply to the Oil and Gas Commission's Advisory Committee for a request to the Oil and Gas Commission to authorize one or more persons to facilitate settlement, by a process of consensual Appropriate dispute resolution, of a dispute related to the decision of the Commission described above. A description of the dispute and the grounds for this application are as follows: *(Please use the back of this form or attach additional sheets, if necessary.)*

1. Name:		Title:	
Signature:		Company:	
Address:			
Date:	Phone:	Fax:	Email:
2. Name:		Title:	
Signature:		Company:	
Address:			
Date:	Phone:	Fax:	Email:

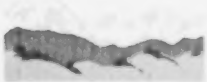
The personal information requested on this form is collected under the authority of and used for the purpose of administering the Oil and Gas Commission Act. Under certain circumstances, some information may be released subject to the provisions of the Freedom of Information and Protection of Privacy Act. If you have any questions about the collection, use or disclosure of this information, contact the Corporate Services Branch, Records Administrator, in Fort St. John at the address above.

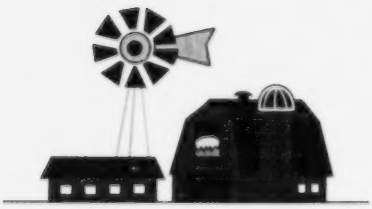
OIL AND GAS COMMISSION

SURFACE RIGHTS IN BRITISH COLUMBIA

A Guide to the Legislation and Regulations for the Oil and Gas Industry

10 July, 2001





This Guide will be updated annually as legislative and regulatory changes occur

Acknowledgement

This edition is an up dated version of the original booklet of the same title prepared by Harvey W. Sasaki, P.Ag. and published in 1988 by the Ministry of Agriculture and Fisheries.

The major change to the document is the addition of pipelines. I

STAKEHOLDER RELATIONS AND COMMUNICATIONS BRANCH

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http://www.ogc.gov.bc.ca Ph: (250) 261-5700 24 Hr.

A Guide to the Legislation and Regulations for the Oil and Gas Industry
11 July, 2001

Introduction

1.1 Objective

The objective of the guide is to outline the petroleum and natural gas exploration, production and pipeline transportation processes as it relates to the property rights of a landowner, and in particular to surface rights, right-of-entry, statutory rights of way, mediation and arbitration and expropriation. It provides a guide to the legislation and regulations governing the petroleum and natural gas industry in British Columbia.

NOTE: This guide is not the law, but only a summary of the legislation and regulations pertaining to surface rights and the petroleum and natural gas industry in British Columbia. Although every effort has been made to avoid errors, this brochure may contain errors, or legislation referred to in the brochure may change after the brochure is printed and distributed. This brochure is not a substitute for the legislation or for legal advice. If there is a discrepancy between this Guide and the legislation and regulations, the legislation and regulations are the final authority.

1.2 Land Ownership rights in relation to oil and gas developments

When a person purchases a parcel of land, the sale conveys to the new owner all of the rights of private property. Those rights are essentially those which were conveyed in the original Crown grant when the title was passed from the Crown to the original private owner. In that original transaction, the Crown may have withheld certain rights. Title to most private lands does not include the right, title or interest to geothermal resources, minerals, coal, petroleum or gas that may be found in or under the land.

Section 50 - "Exceptions and reservations", of the *Land Act* identifies the interests, rights, privileges and titles currently reserved by the Crown upon disposition of Crown land.

The majority of petroleum and natural gas rights in the Province of British Columbia are owned by the Crown in the Right of the Province. A small percentage of petroleum and natural gas rights are privately owned as a result of being included with Crown grants of surface lots issued prior to 1891. This primarily occurred in areas of early settlement. The Federal Government holds title to a very small portion of British Columbia petroleum and natural gas rights by virtue of various Federal-Provincial agreements.

The exploration for, and the development and production of, Provincially owned petroleum and natural gas resources is regulated under the *Petroleum and Natural Gas Act*. The disposition of the petroleum and natural gas rights, by the Ministry of Energy and Mines for the Province, grants companies the right to explore for, develop and produce petroleum and natural gas resources. The Province receives payments for the sale of those rights through a competitive bidding process, and from royalties on the sale of any petroleum and natural gas produced and sold. The funds received by the Province are used to support Provincial programs to benefit all British Columbians.

The activities associated with the exercise of the rights by the companies affect and may disrupt the normal use of the surface of the lands. The *Petroleum and Natural Gas Act* also sets out the rules and regulations governing the exploration, development and production of the petroleum and natural gas resources of the Province. The *Pipeline Act* establishes the rules and regulations for transportation of oil and gas by pipelines, including the taking of land and the expropriation of private land. The Oil and Gas Commission is responsible for administering the *Pipeline Act*, as well as the portions of the *Petroleum and Natural Gas Act* which deal with exploration, development and production activities.

For companies designated as natural gas utility companies, the *Gas Utility Act* provides the rules for expropriating land.

For Federally regulated pipelines, the National Energy Board (NEB) is the regulator and their governing legislation set out the procedure for taking of lands. The NEB should be contacted directly for details of their processes for pipelines under their jurisdiction.

1.3 Builders Lien Act

Under section 3 (1) of the *Builders Lien Act*, a builders lien may be filed against the land for work done on an "improvement", such as a pipeline or production facility, if the improvements are done with the prior knowledge of the owner, even if the owner has not requested them. However, section 3 (2) also provides that a lien may not be filed against the land if a "notice of interest" form as set out in the Builders Lien Forms Regulation (B.C. Reg. 1/98) is filed with the Land Titles Office. The "notice of interest" provides that the owner's interest in the land is not bound by a lien claimed under the *Builders Lien Act* for an improvement on the land unless that improvement is undertaken at the express request of the landowner.

Landowners should be aware of the *Builders Lien Act* and if appropriate, make arrangements to have a notice of interest filed with the Land Title Office for a project that may be proposed on their land. This subject may also be addressed in a surface land agreement negotiated with a company.

1.4 Definitions

To assist in the use of the Guide, specific terms related to surface rights and petroleum and natural gas exploration and development have been defined. These terms are used throughout the text. Specific references to sections of legislation have also been highlighted to aid in future reference.

Expropriate – means the taking of land by an expropriating authority under an enactment without the consent of the owner.

Geophysical Exploration—the investigation of the subsurface by seismic, gravimetric, magnetic, electric or geochemical operations.

Lessee—in the context of a surface lease, usually the petroleum company who acquires the right to use the property, or portion thereof, of the landowner from whom a lease is obtained.

Lessor— in the context of a surface lease, usually the landowner who rents real property, or conveys or leases the right of the use of real property, to a petroleum company for purposes of exploring for or producing petroleum and/or natural gas.

Seismic Approval— an approval by the Oil and Gas Commission, of an application from a company to conduct a seismic program under the *Petroleum and Natural Gas Act.*

Surface Lease—any agreement entered into by an owner or occupant with a company under which the surface of the land may be used for any purpose, or for which a right-of-entry order can be granted and which provides for the payment of compensation (rental or otherwise). A surface lease is registerable under the *Land Title Act*

2 Oil and Gas Activities

2.1 Surface Rights

The *Petroleum and Natural Gas Act* recognizes that the entry, occupation or use of privately held lands may be necessary to explore for, develop or produce the Province's petroleum and natural gas. The *Act* outlines the process by which the entry, occupation and use of private land by petroleum companies is permitted. Additionally, the *Act* provides for compensation to be paid by the petroleum company for the entry on the land. In the case of continuing use of the land, the *Act* provides for the payment of an annual rent.

When a petroleum company requires land for their operations, the landowners will be approached by either a land agent or surveyor to discuss the project and obtain consent to do a survey of the area required. This is notwithstanding the right, specified in the *Trespass Act*, of a British Columbia Land Surveyor to carry out a legal survey. When an area has been surveyed, a land agent representing the company will contact the land-owner to discuss the proposed project and negotiate a Surface Lease for any above ground structures or a seismic (geophysical) project, or an Easement (Right-of-Way) Agreement for the below ground structures which may be required by the company.

2.1.1 Seismic Projects

The right of access to private land for seismic operations is entirely subject to agreement between company and landowner. The seismic operation may entail a survey of the proposed line and clearing away of any obstacles, so trucks and equipment can drive along the line. The actual conduct of the project may include the drilling of shallow, small diameter "shot holes" and the detonation of a small explosive charge at the bottom of the holes, or the use of truck-mounted vibrator equipment. After the project has been completed, the company representative should return to ensure any damage that might have occurred is repaired or to arrange to compensate the landowner and to obtain a release. Payments to the landowner may include a lump sum consideration plus any crop loss, paid for the rights granted prior to entry. Compensation for damages will normally be paid after the seismic recording has been completed.

2.1.2 Surface Lease

When a company has determined the location upon which it wishes to conduct an operation, a land agent for the company will contact the landowner to discuss the project, have the location surveyed if not already done, and negotiate an agreement. This agreement is referred to as a Surface Lease and is a legal and binding contract which specifies the terms and conditions of the use of the surface of the land. The Surface Lease is a grant by the landowner to the company of a right to enter onto the land to drill a well or construct and maintain any above ground structures necessary for the petroleum company's operations (i.e., wellsite, battery). The surface lease should specify any conditions necessary to describe the responsibilities and commitments by both the operator and landowner, including the payment of compensation. The Surface Lease Regulation, BC Reg 497/74, prescribes the minimum content of a Surface Lease. It must be noted that the prescribed content and conditions should not be construed to be limiting.

A standard Surface Lease agreement form has been developed jointly by the Canadian Association of Petroleum Landmen and landowners in the Peace River area. The standard Surface Lease agreement should be considered to be a guide and modified to reflect the needs of each situation.

2.1.2.1 Renegotiation of a Surface Lease

By statute, the rental provisions of a Surface Lease may be renegotiated every five years. Notice must be given by prescribed form to the petroleum company, by registered mail at its address for service as shown in the Surface Lease, on or after the 5th anniversary of the Surface Lease. Procedures for the renegotiation of a Surface Lease are set out in section 11- "Renegotiation" and section 12 - "Arbitration" of the *Petroleum and Natural Gas Act*. If an agreement has not been reached 8 months after the notice was sent, either party may apply to the Mediation and Arbitration Board for an Arbitration hearing. The forms are available at the Board office in Fort St. John.

2.1.2.2 Termination of a Surface Lease

The Surface Lease Regulation, B.C. Regulation 497/74 specifies four terms and conditions that every Surface Lease must contain. Two sections specify conditions for termination of a Surface Lease. Section 1. (c) provides that a lease may be terminated by the grantor, if a default on payment of rentals continues for ninety days after demand for payment has been made. Section 1. (d) provides that the lessee may terminate the lease on or after the second anniversary date of the lease, upon not less than ninety days notice to the grantor. Additionally, a lease may be terminated upon the mutual agreement of all involved parties.

2.2 Mediation and Arbitration

As previously indicated, the *Petroleum and Natural Gas Act* allows for mutual agreement through the private negotiation of a surface lease between landowners and petroleum companies. If private negotiations fail to produce a satisfactory agreement for both parties, the *Act* establishes a Mediation and Arbitration Board, which makes orders and rulings respecting entry, occupation conditions and compensation of land required for exploring for, developing, producing or storing petroleum and natural gas. The role of the

Board is to ensure that when agreements cannot be reached between a petroleum company and a landowner, the company can acquire access to its petroleum and natural gas rights and that surface owners are fairly compensated as a result.

Upon proper application and after conducting a hearing, the Board may issue an order authorizing entry upon the land, that details the terms and conditions for both the company and landowner. The procedures for application for mediation and arbitration are set out in section 16 "Application for mediation and arbitration", of the *Petroleum and Natural Gas Act*. Most surface leases in British Columbia are negotiated and therefore never go before the Mediation and Arbitration Board. If both parties are aware of their legal rights and obligations, and conduct themselves in a responsible manner, an agreement can usually be negotiated. A negotiated agreement is more likely to serve the needs of both the landowner and the petroleum company while minimizing hardship to both.

2.2.1 Mediation

Mediation is the intervention by the Board to promote settlement or compromise. Upon receipt of an application under section 16 - "Application for mediation and arbitration" of the *Petroleum and Natural Gas Act*, the Board Administrator will contact both parties and attempt to determine the issue(s) and facilitate an agreement. If the Administrator is not successful, the Chair of the Mediation and Arbitration Board will appoint a Mediator, to inspect the property and conduct a Mediation hearing. The mediator will attempt to resolve the problems and issues that are preventing the parties from reaching agreement. If mediation fails, the mediator may issue a Right -of-Entry Order. Outstanding issues are then subject to an Arbitration hearing. Procedures for mediation hearings are outlined in section 18 - "Mediation hearing" of the *Petroleum and Natural Gas Act*.

2.2.2 Right-of-Entry

The agent for the petroleum company may apply to the Mediation and Arbitration Board for a Right-of-Entry Order pursuant to section 16 - "Application for mediation and arbitration" of the *Petroleum and Natural Gas Act* when a landowner refuses to grant a Surface Lease. The Right-of-Entry Order grants a company the right to enter, occupy or use a specified area for purposes such as drilling or development of petroleum and natural gas. Before making an Order, the mediator will conduct a hearing between the landowner and the company. Through mediation, the mediator will attempt to have the parties reach an agreement. In the event of failure to reach an agreement, the Mediator may issue a Right-of-Entry Order. While granting the petroleum company the right-of-entry to the land, the *Petroleum and Natural Gas Act* specifies that the Mediator must order the applicant to pay to the landowner a partial payment for loss or damage caused, for the entry to the land. These requirements are contained in section 19 - "Entry, occupation or use order", of the *Petroleum and Natural Gas* Act.

It is important to note that the *Petroleum and Natural Gas Act* specifies that a petroleum company must acquire a Surface Lease or Right-of-Entry Order before entering upon private land. The Surface Lease or Right-of-Entry Order should be filed with the Registrar of Land Titles as a charge against the Land Title. This charge is the legal claim and notice of the petroleum company's interest in the land.

2.2.3 Arbitration

Arbitration is the hearing and determination of a dispute by the Board with respect to the lump sum compensation and annual rent to be paid to the owner and/or occupants of the land. During arbitration, the Board accepts evidence and hears arguments from the involved parties before considering compensation. Procedures for arbitration hearings are set out in section 20 - "Arbitration hearing", of the *Petroleum and Natural Gas Act.*

In determining the amount of compensation, section 21 - "Determining amount", of the *Petroleum and Natural Gas Act* specifies items that the Board may consider.

Application for arbitration may also be made pursuant to section 12 – "Arbitration: other provisions", of the *Petroleum and Natural Gas Act* when rental provisions are not renegotiated under section 11 - "Renegotiation", within 6 months after the expiration of the notice.

2.2.4 Certificate of Restoration (CoR)

Section 84 - "Certificate of restoration" of the *Petroleum and Natural Gas Act* specifies that a well, test hole or production facility is deemed not to be abandoned until a CoR has been issued by the Oil and Gas Commission. Before a company can terminate its Surface Lease or Right-of-Entry Order with the landowner, it must remove all equipment, restore all affected lands and apply for a CoR from the Commission. The application must be accompanied by a *Waste Management Act* Site Profile, which is used to determine if a location may be contaminated. If the potential for contamination exists, further investigation of the location will be ordered and if contamination exists, it must be remediated to the appropriate standards. The Commission may issue the CoR when the company files a signed release from the landowner or upon satisfactory examination by the Commission. For wellsite developments within the Agricultural Land Reserve, confirmation is required from the Land Reserve Commission that the reclamation of the development is complete prior to the issuance of a CoR.

3 Pipelines

3.1.1 Agreement

The successful development of a well and subsequent production of petroleum and/or natural gas may require additional facilities such as pipelines. This usually requires a new taking of land and therefore the negotiation of a new agreement between the landowner and company.

The agreement concerning the right of way for the pipeline will be registered by the company under the *Land Title Act* as a Statutory Right of Way. The agreement spells out the rights and responsibilities that a company has regarding the right of way including the right to enter onto land to construct and maintain a pipeline or lines and necessary facilities and the payment of compensation to the landowner. For surface facilities not on a well site, the method of compensation may have an annual component to it. Any above ground pipeline facility constructed in connection with the pipeline should be considered. The procedure in negotiating an agreement is similar to that outlined under the Surface Lease Section. The provisions of an agreement may include compensation for damage due

to pipeline maintenance, the number of pipelines under the agreement, ownership of the pipeline when a company wants to abandon it and any other appropriate matter.

Agreement not reached

When an agreement with a landowner cannot be reached, the following means of appropriating land are prescribed by the *Pipeline Act;*

1. **Flow Lines –** The landowner or company may apply to the Mediation and Arbitration Board, as described above. Flow lines are defined in the *Pipeline Act*, and connect wellheads with batteries or facilities that may or not be on the well lease, or to other pipelines.

2. **All other pipelines –** The *Pipeline Act* refers to Part 7 of the *Railway Act* which describes a process for taking land including such things as offer and notification to landowner, registering documents with the Land Titles Office, and referring compensation matters to the Expropriation Compensation Board.

Gas Utility Act

The *Gas Utility Act* grants a gas utility company a right to expropriate land using the *Expropriation Act* if an agreement with the landowner is not achieved. It also allows the gas utility company in urgent circumstances, to apply to the BC Utilities Commission to take land immediately and within a reasonable time, refer the matter to the Expropriation Compensation Board to determine compensation to the landowner. Gas utility companies in the Province include BC Gas, Centra Gas and Pacific Northern Gas.

Federally Regulated Pipelines

Questions regarding the construction and operation of federally regulated pipelines should be referred to the National Energy Board.

4 Agricultural Land

For land within the Agricultural Land Reserve in the oil and gas producing areas of the Province, General Order 293/95, made by the Agricultural Land Commission, outlines soil sampling requirements in addition to the terms and conditions for exemption from the formal approval process under the *Agricultural Land Reserve Act.* The Land Reserve Commission, as it pertains to agricultural land, has a duty to protect the agricultural values of the land. In disputes between a landowner and a company put before the Land Reserve Commission, the preservation of agricultural values will be foremost.

5 Additional References

5.1 Legislation

As previously indicated, the *Petroleum and Natural Gas Act* is the primary legislation regulating petroleum and natural gas exploration, development and production in British Columbia as is the *Pipeline Act* for oil and gas pipelines. In addition, there is other

legislation, which may or may not be included in the listing below, that may pertain to exploration, well drilling and pipelines on agricultural land. For specific information, refer to the pertinent legislation, copies of which can be obtained from the Queen's Printer.

Agricultural Land Reserve Act (formerly the ***Agricultural Land Commission Act***)

Administered by: Ministry of Sustainable Resources Management, Provincial Land Reserve Commission.

Builders Lien Act

Administered by the Ministry of Competition, Science and Enterprise

Gas Utility Act

Administered by the British Columbia Utilities Commission

Heritage Conservation Act

Administered by the Ministry of Community, Aboriginal and Women's Rights and in part by the Oil and Gas Commission

Land Title Act

Administered by the Ministry of Sustainable Resources Management

Land Survey Act

Administered by the Ministry of Sustainable Resources Management

Pesticide Control Act

Administered by the Ministry of Water, Land and Air Protection

Petroleum and Natural Gas Act

Administered in part by Ministry of Energy and Mines, and in part by the Oil and Gas Commission.

Pipeline Act

Administered by the Oil and Gas Commission

Soil Conservation Act

Administered by the Ministry of Agriculture, Food and Fisheries

Trespass Act

Administered by the Ministry of Attorney General

Waste Management Act

Administered by the Ministry of Water, Land and Air Protection and in part by the Oil and Gas Commission

Water Act

Administered by the Ministry of Sustainable Resources Management and in part by the Oil and Gas Commission

Weed Control Act

Administered by the Ministry of Agriculture, Food and Fisheries

5.2 Standard Forms

There are a number of forms currently in use, which pertain to surface rights. A brief description of each is provided in the following list.

5.2.1 Standard Surface Lease Agreement

A standard surface lease agreement was prepared jointly by representatives of the BC Agricultural community and the petroleum industry. This form may be used as a basis of a Surface Lease Agreement. Circumstances may vary and as such, this model agreement should be used with discretion and consideration given to the addition or deletion of clauses and terms and conditions as the situation requires.

A copy of the standard lease agreement can be obtained from most of the BC-based and industry associations listed in the following section titled Contacts.

5.2.2 Notice to Lessee

This form is used by the landowner to provide notice to the petroleum company for a rental renegotiation as per section 11 - "Renegotiation" of the *Petroleum and Natural Gas Act*. Refer to the section on Renegotiation of a Surface Lease, above.

5.2.3 Application for Arbitration

This form is used by the landowner or his agent to apply for arbitration of a rental renegotiation pursuant to section 12 - "Arbitration" of the *Petroleum and Natural Gas Act*. Refer to the section on Arbitration, above.

5.2.4 Application for Mediation and Arbitration and Permission to Enter

This form is used by the petroleum company when applying for Right-of-Entry onto deeded land when:

(a) an impasse has developed between the landowner and company, and consent is not obtainable; or

(b) the company and landowner mutually agree that entry should be by way of Board Order rather than a signed lease agreement.

Landowners use this form when applying for damages which occurred during the entering, occupation or use of the land.

Upon receipt of the application, a mediator, appointed by the Chair of the Board, investigates the request, including discussions with surface owner and petroleum company and on-site inspection, and tries to resolve the impasse. Refer to the section on Mediation and Arbitration, above.

CONTACTS

Oil and Gas Commission
Headquarters – 200, 10003-110 Avenue, Fort St. John, BC V1J 6M7 Ph. 250 261 5700
Branch office –Box 9329 Stn Prov Govt, Victoria B.C. V8W 9N3 Ph- 250 952 0296

Provincial Land Reserve Commission
4940 Canada Way, Burnaby B.C. V5G 4K6 Ph 604 660-7000

Canadian Association of Petroleum Producers
2100, 350-7th. Avenue S.W., Calgary, Alta. T2P 3N9 Ph. 403 267-1100

Canadian Association of Petroleum Landmen
1900,500-4th. Avenue S.W., Calgary, Alta. T2P 2V6 Ph. 403 237-6635

Mediation and Arbitration Board
10142 – 101 Avenue, Fort St. John, BC V1J2B3 Ph. 250 787-3403

National Energy Board
444 Seventh Ave. SW, Calgary, Alberta T2P 0X8 Ph. 403 292-4800

National Farmers' Union –National Office
2717 Wentz Avenue, Saskatoon, SK. S5K4B6 Ph. 360 652-9465

North Pine Farmers' Institute
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General Development Permit

Guidance Document

July 10, 2003

OIL AND GAS COMMISSION

General Development Permit
Guidance Document

Executive Summary

A General Development Permit (GDP) is an application tool that allows for project level review, consultation, and approval in principle for works in a given project area. This process will allow for enhanced First Nations consultation, improved cumulative impact management and reduced processing times for permits and authorizations.

A GDP is best suited to development fields on Crown land where multiple wells and pipelines are anticipated during a given drilling season and a high likelihood of drilling success exists.

A template is in preparation and will be provided upon request.

Key Dates: July 31 – Deadline for Expressions of Interest
September 15 – Deadline for Overview Plan
November 1 – Deadline for Final GDP Application

What is a General Development Permit?

A General Development Permit (GDP) offers the opportunity to apply for project level review, consultation, and approval in principle for works in a given project area. This process will allow for enhanced First Nations consultation, improved cumulative impact management and a leveling of workloads for all.

The GDP process will:

i) create efficiencies in project design
ii) enhance First Nation and stakeholder consultation
iii) provide improved opportunity to manage cumulative impacts

The specifics and the process involved with GDP applications are intended to better meet the needs of First Nations, government, industry and stakeholders. An adaptive management approach will allow the incorporation of successful experiences from each generation of GDP into future versions of these guidelines.

Under what circumstances should a GDP be applied for?

A GDP is best suited to development fields on Crown land where multiple wells and pipelines are anticipated during a given drilling season and a high likelihood of drilling success exists.

A GDP is not suited to exploration projects where drilling locations are uncertain and likely to be amended during the drilling season as new information becomes available.

Geophysical activities will not be approved-in-principle under a GDP. Specifics pertaining to potential geophysical programs are welcomed to provide a comprehensive picture of planned development within a project area; however, any details provided will be for information purposes only.

The diversity and sensitivity of resources within a general development area needs to be understood.

Interested parties are encouraged to contact the OGC to help determine if a GDP application would be appropriate for any given project.

GDP Process and Timing

The GDP application and approval will occur as a three-step process, A-C below:

A Expression of Interest

The proponent must submit, to the Commission, a letter of interest that describes the area of interest and the anticipated scope of the project. This letter must be accompanied by a general map, at an appropriate scale, that shows the location of the project area under consideration. This letter will initiate discussion with the Commission and First Nations regarding the suitability of a GDP application. As the information requirements depend in part on the diversity and sensitivity of the resource base, this step will enable the Commission to provide direction regarding studies or assessments that may be required as part of the application (e.g., fish habitat, cultural resources, terrain sensitivity). The deadline for receipt of an expression of interest in winter projects is July 31st.

Note: The expression of interest does not bind a proponent to the GDP process. Should it be determined that the GDP is not a suitable or desirable method of application, the standard process for individual applications may still be followed.

B Overview Plan

The overview plan is a compilation of all of the available, relevant (non-confidential) information relating to the project at the time of submission. To be accurate and comprehensive, the plan needs to be a collaborative effort involving both drilling and pipeline personnel from the company. The purpose of the overview plan is to provide as much detail about the project as possible in order to initiate project level review and consultation with First Nations, stakeholders and government.

The overview plan should include descriptions of proposed operating procedures and operational ground rules for the project. The overview should include the results of any field scouting, environmental assessments, and archaeology/cultural overview assessments. Mapping for the overview plan should show firm well locations, contingent well locations, locations of corridors for access and pipelines including possible alternate routes. Mapping must be submitted at both 1:50,000 and 1:20,000 scales. The deadline for overview plan submission for winter programs is September 15th. Within 2-4 weeks, the OGC will provide the proponent with review process feedback as well as any pertinent First Nations and stakeholder feedback that the commission has received.

C Final GDP Application

This is the finalized project plan for the drilling season. It should include all known wells, pipelines, facilities and access corridors that are planned. The format for the final application is an expansion of the format used in the overview

application. The final GDP application should be a refined version of the overview plan and contain all relevant, up to date information about the project. This plan should incorporate feedback from the review and consultation process of the overview plan. This plan must include finalized maps and any requested assessments (e.g., archaeology, fish habitat, etc.). Mapping must include a 1:50,000 scale map, a 1:20,000 scale map, and survey plans for the individual wellsites. The deadline for final GDP applications for winter drilling projects is November 1st. The expected timeline for the OGC to make decisions on the approval of Final GDP plans is 15 working days. This timeline may be greater if there are unresolved issues or if the application is lacking required information.

Subsequent to GDP approval, submission of individual applications (e.g., well authorization, pipeline application) will be required for authorization to access Crown land and to perform the works. These applications may now be processed expeditiously as they have already undergone review and consultation under the GDP.

GDP Duration

The GDP approval will be considered valid for a period of 18 months from the date of approval. Applications for activities that are made after the approval has expired must undergo review and consultation, either through another GDP or individual application.

Any authorizations or permits that are issued subsequent to the GDP review, consultation and approval process will be valid for the period specified by that authorization or permit.

Consultation

One of the benefits of the GDP process is the opportunity for enhanced engagement of First Nations and stakeholders. The GDP allows consultation and stakeholder involvement to occur early during project development instead of later when individual applications are submitted. The process has been developed with timelines that are intended to better facilitate effective and meaningful consultation. The input gathered from First Nations and stakeholders should be incorporated into the Final GDP application in a way that attempts to mitigate concerns related to the project.

The proponent is expected to identify First Nations and stakeholders that may be affected by the proposed development and allow them the opportunity for input. It is expected that the proponent will have initiated the public consultation process by the time the overview plan is submitted to the OGC. Any measures taken by the proponent to resolve concerns regarding the proposed development should be recorded. Any concerns that are unresolved must be documented within the final GDP application.

Confidentiality and Sensitivity

Companies and First Nations involved with GDPs should recognize that there might be some sharing of confidential information during this process. The party sharing that information should clearly indicate the sensitivity, so that confidentiality can be respected. It should be recognized by First Nations that information such as zones of interest, depth, and specific techniques for drilling and completion are among those topics that are likely to be confidential. Similarly, companies must recognize that information that may be shared by First Nations regarding heritage sites and community areas of interest is likely to be confidential. In either case, if sensitive information is distributed, it is the responsibility of the party sharing information to clearly indicate the need for confidentiality.

For strategic reasons (e.g., impending land sales) a proponent may have some wells in a given area that are purposefully not included in the GDP process. While proponents are encouraged to convey the existence of such locations to the OGC and to First Nation groups to assist in the planning process, there is no requirement to do so. Such applications must, however, be applied for individually and will not be part of the GDP process.

Content, Standards and Detail

The GDP application should be comprehensive and explicit. Information should be focused on potential surface impacts and any land use conflicts that may result from the project. It should contain accurate information regarding what is known about the project at the time of submission. This includes details of firm and contingent wells, pipeline and access routes including alternate routes that may be used, and logistical information relevant to the project. The application should demonstrate that planning has been undertaken to minimize the environmental footprint of the proposed activities. Such planning may include the coordination of access routes and pipelines, use of previously disturbed areas, and details of environmental protection measures that will be implemented. When access or pipeline corridors are planned along existing seismic lines a description of the existing line condition (line width, state of re-growth, straight line vs. avoidance cut) should be included. The operations set out in the GDP should be planned to meet seasonal requirements (e.g., the drilling sequence of a winter project should take into account the distance of the wells from high-grade access and the onset of spring freshet to minimize the potential for environmental damage). The GDP should include a description of how operations are to be conducted and a logistical schedule of the anticipated events.

The plan should set out the work or measures to be taken during the next stage of application or development. For example: if the archaeological or cultural resources overview assessments performed at the preliminary planning stage indicate a high potential area, the preliminary plan should outline what steps will be taken to protect the archaeological/cultural resource (such as a preliminary field reconnaissance or archaeological impact assessment) prior to the final application. Similarly, the final

application should address contingency plans at the operational stage (e.g., what measures would the proponent take to protect a bear den should one be located during the construction phase of the project, etc.).

By the time a proponent is prepared to submit a Final GDP application, there should be enough detail to identify the presence or absence of any critical wildlife features, heritage sites and community areas of concern. These should be mapped and/or documented, as appropriate, along with mitigation plans to address issues or concerns.

In order to facilitate the construction needs in the field, the GDP process will allow proponents to designate a review area around their project. This will allow limited movement of planned activities as operationally required within the designated review area. Infrastructure including borrow pits, decking sites, camps, sumps, etc. could be located as operationally feasible at the time of construction. To use this process, **the applicant must clearly identify all review areas on the GDP maps of appropriate scale**. The review areas are to be set by the proponent based on the type of work that is proposed but must be consistent with the parameters set for Wellsite/Access Review Areas as described in Information Bulletin dated November 5, 2002. Each level of planning (overview application, final GDP application, individual activity application) should include the best-known information with regard to the anticipated location and area (in hectares) required for infrastructure (borrow pits, decking sites, camps, sumps, etc.) In addition to defining the review area, the proponent must establish ground rules for selecting the locations of infrastructure within the review area, and these must be consistent with the *Maximum Disturbance Review Criteria* (MDRC). The proponent should also consider any relevant input received from the OGC and First Nations for incorporation into final application (e.g., within review area the following have been identified as areas of concerns…).

Any overlapping GDP applications will be rationalized and resolved by companies or with OGC facilitation.

Amendments to a GDP

An amendment to the GDP will be considered for the purpose of adding more works to the project or modifying the season during which the works are to be performed.

Amendments and extensions to the GDP are to be limited to an annual basis and will not be permitted during peak season – November 1 through March 31

Amendments to Individual Activities

Amendment of activities that were reviewed and consulted on under the GDP may be made at the time of application for that individual activity or after that activity has been authorized; however, depending on the nature of the amendment, further OGC review and consultation with First Nations may be required.

Should the proponent wish to apply between November 1 and March 31 for activities within the project area that were not included in the GDP application, individual applications will be required and be subject to the standard OGC application process.

Applications for Permits and Authorizations

When application is made for an activity that is part of an approved GDP, a simplified checklist will outline the requirements for application. A simplified Timber Harvesting Form has been developed for GDP activities where the harvesting of Crown timber is required. These modified forms will be posted on the OGC website.